Y4.In8/13:P87/3
94-2

94th Congress }
2d Session }

COMMITTEE PRINT

NATIONAL POWER GRID SYSTEM STUDY—AN OVERVIEW OF ECONOMICS, REGULATORY, AND ENGINEERING ASPECTS

UNIVERSITY OF FLORIDA LIBRARIES
APR 1976
DOCUMENTS DEPT.

A STUDY

PREPARED BY THE

CONGRESSIONAL RESEARCH SERVICE

AT THE REQUEST OF

LEE METCALF, *Chairman*

SUBCOMMITTEE ON MINERALS, MATERIALS AND FUELS

OF THE

COMMITTEE ON INTERIOR AND INSULAR AFFAIRS
UNITED STATES SENATE

Printed for the use of the
Committee on Interior and Insular Affairs

U.S. GOVERNMENT PRINTING OFFICE
67-740 O WASHINGTON : 1976

COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

HENRY M. JACKSON, Washington, *Chairman*

FRANK CHURCH, Idaho
LEE METCALF, Montana
J. BENNETT JOHNSTON, Louisiana
JAMES ABOUREZK, South Dakota
FLOYD K. HASKELL, Colorado
JOHN GLENN, Ohio
RICHARD STONE, Florida
DALE BUMPERS, Arkansas

PAUL J. FANNIN, Arizona
CLIFFORD P. HANSEN, Wyoming
MARK O. HATFIELD, Oregon
JAMES A. McCLURE, Idaho
DEWEY F. BARTLETT, Oklahoma

GRENVILLE GARSIDE, *Special Counsel and Staff Director*
DANIEL A. DREYFUS, *Deputy Staff Director for Legislation*
WILLIAM J. VAN NESS, *Chief Counsel*
OWEN J. MALONE, *Senior Counsel*
D. MICHAEL HARVEY, *Deputy Chief Counsel*
W. O. (FRED) CRAFT, Jr., *Minority Counsel*

SUBCOMMITTEE ON MINERALS, MATERIALS AND FUELS

LEE METCALF, Montana, *Chairman*

HENRY M. JACKSON, Washington
J. BENNETT JOHNSTON, Louisiana
JOHN GLENN, Ohio
RICHARD STONE, Florida
DALE BUMPERS, Arkansas

PAUL J. FANNIN, Arizona
CLIFFORD P. HANSEN, Wyoming
DEWEY F. BARTLETT, Oklahoma

D. MICHAEL HARVEY, *Deputy Chief Counsel*

MEMORANDUM FROM THE SUBCOMMITTEE CHAIRMAN

Early last year Representative Richard Ottinger of New York and I requested the Congressional Research Service of the Library of Congress to study the concept of a national power grid for electrical power transmission. The CRS study, done in part by a contractor and consultants and in part by CRS in-house, was completed in November 1975. Its primary findings on feasibility, based on present and reasonably foreseeable technology, are:

There is not enough load diversity among the time zones to justify a grid.

Most of the seasonal load diversity is already utilized, and the remainder is too scattered to justify a grid.

The regional reserve pools will practically evolve into a national grid within 10 years, and this appears to be the best procedure.

Improved load factors will reduce load diversity and decrease excess power available to the grid.

Existing studies indicate that reserves might be reduced 1 to 3 percentage points as a result of a strong national power grid without reduction of present reliability standards.

The continuing trend toward summer peaks nationwide reduces load diversity.

There is merit to linking the Southwest Power Pool with the Electric Reliability Council of Texas.

The only way a link between the West and the Midwest would be feasible is if large mine-mouth generating facilities are built in the western coal areas.

Substantial savings can be realized through reduced system reliability. Reducing reserves to a level of 15 percent of projected annual peak demand would yield total present value savings over 10 years of about $20 billion. Reducing reserves to 17.5 percent of peak demand would yield comparable savings of $9.5 billion.

FPC needs authority to order wheeling of power and the related facilities without declaring a state of emergency.

Small utilities which do not currently have access to power pools would benefit from a national grid open to all.

In several parts of the study, the authors state that there appears to be no economic justification for establishing a separate national grid because the benefits would not match the costs. It should be noted here that while Congressman Ottinger's and my legislation (S. 1208 and H.R. 5048) contemplates changes in ownership and operation of the existing grid system and any necessary additions, it does not provide for the establishment of a separate, duplicative grid system.

One primary problem regarding the study was that the authors were forced to rely on data supplied by Edison Electric Institute, National Electric Reliability Council, and other industry sources, as well as the Federal Power Commission, National Regulatory Commission and Federal Energy Administration, which are themselves largely reliant upon sources within an industry which strongly opposes a national grid. In fact, the only substantial study of load diversity to date has been by EEI, on its own data for the years 1962–71.

The study is admittedly and necessarily preliminary. And it does not address—nor were the authors asked to address—the merits of public ownership and control of a national power grid. Indeed, many of the benefits projected to be derived from a national grid system relate to the areas which were not covered by this study. Such issues as the need for common carrier rights in power transmission, the ability of an integrated grid system to promote competition among wholesale power generation units, and the efficiencies to be realized from coordinated national planning in this capital intensive area involve social considerations as much as technological considerations.

I sent copies of the report to several organizations that are directly concerned with and knowledgeable about improved transmission systems. They are the American Public Power Association, R. W. Beck and Associates, Edison Electric Institute, Ken Holum & Associates, the Missouri Basin Systems Group and the National Rural Electric Cooperative Association. The study and the excellent comments together provide the most authoritative commentary on a national power grid that has ever been assembled in this country. It will, I believe, be a useful document to us within the Interior Committee, to the Congress and to all segments of the power industry. I therefore request that it be published as a committee print.

LEE METCALF,
Chairman, Subcommittee on Minerals, Materials and Fuels.

LETTERS OF TRANSMITTAL

U.S. SENATE,
COMMITTEE ON GOVERNMENT OPERATIONS,
Washington, D.C., January 30, 1975.

MR. LESTER JAYSON,
Director, Congressional Research Service,
Library of Congress,
Washington, D.C.

DEAR MR. JAYSON: There are many unanswered questions about the feasibility of developing a National Power Grid system for the transmission of electricity. Although the concept has been developed and discussed over the years, more specific data is needed on the technology for coast to coast transmission of electricity, and the economic and environmental impact of such a system. Our interest in this concept is very strong.

We understand that the Congressional Research Service has funds available to contract out studies of this nature. We request that such A 3 to 5 month, $50,000 study could give us those tools.

We would be glad to meet with the CRS to discuss this in further detail. We look forward to hearing from you.

Very truly yours,

LEE METCALF,
United States Senate.
RICHARD OTTINGER,
Member of Congress.

THE LIBRARY OF CONGRESS,
CONGRESSIONAL RESEARCH SERVICE,
Washington, D.C., November 18, 1975.

Hon. LEE METCALF,
Dirksen Senate Office Building,
Washington, D.C.

DEAR SENATOR METCALF: In your letter of January 30, 1975 you requested a study of what would be involved in developing a National Power Grid system for the transmission of electricity. As we mentioned in our letter of May 16 our decision was to contract for the economic, regulatory, and technological elements of the study and to conduct within CRS the legal and environmental portions of the study.

Transmitted herewith is the final product—two copies of the report of the contractor, CH2M Hill of Bellevue, Washington and two copies of both the American Law Division and the Environmental Policy Division studies. These latter two studies were prepared by Robert Poling and Gary Pagliano, respectively. Fifteen additional copies of the full study will be delivered to you next week. Dr. Douglas Jones of our Economics Division coordinated the overall project and served as CRS technical representative to the contractor, Mr. George Chatham of the Science Policy Division and Dr. Warren Donnelly also participated in reviewing the contractor's product. We trust it will be useful to your legislative purposes.

Yours truly,

Norman Beckman,
Acting Director, Congressional Research Service.

CONTENTS

Page
Memorandum from Subcommittee Chairman Lee Metcalf ... III
Letter of transmittal from Senator Metcalf and Representative Richard Ottinger to Lester Jayson, Director, Congressional Research Service, Library of Congress, January 30, 1975 ... V
Response from Norman Beckman, acting director, Congressional Research Service, to Senator Metcalf, November 18, 1975 ... V

NATIONAL POWER GRID SYSTEMS STUDY—AN OVERVIEW OF ECONOMICS, REGULATORY, AND ENGINEERING ASPECTS

Letter from Harold M. Mozer, Director, Electrical Engineering, and Lawrence F. Pinson, Project Economist, CH_2M Hill, to Dr. Douglas N. Jones, assistant chief, Economics Division, Congressional Research Service, November 14, 1975 ... 2
Preface ... 3
Summary ... 5
1. Introduction ... 9
    What is it? ... 9
    A power transmission primer ... 10
    National power grid system alternatives ... 12
    Scope of the study ... 12
    Sources of data ... 13
2. Findings ... 15
    Load diversity ... 15
    Reserves ... 15
    Transmission ... 16
    Economic aspects ... 18
    Regulatory considerations ... 20
    Technological questions ... 22
    Additional studies ... 22
3. Load diversity ... 25
    The nature of loads ... 25
    The nature of load diversity ... 28
    A recent study of load diversity—EEI methods ... 38
    Current and future load diversity ... 54
    Summary and findings ... 74
    Footnotes to chapter 3 ... 76
4. Reserves ... 79
    The need ... 79
    Determining reserve requirements ... 81
    Factors affecting reserve levels ... 82
    Reducing reserve requirements ... 91
    How much reliability is needed? ... 99
    Footnotes to chapter 4 ... 100
5. Transmission ... 107
    Purposes of transmission ... 107
    The Nation's power systems ... 108
    Interregional power transfers ... 110
    Western United States—Central United States interconnection study ... 117
    ERCOT–SPP interconnection study ... 121
    Emergency backup ... 122
    Wheeling ... 123
    Footnotes to chapter 5 ... 124

Page

6. Technological questions ---- 127
    Advanced transmission systems ---- 127
    Ultra-high voltage alternating current ---- 127
    Direct current transmission ---- 128
    Control systems ---- 129
    Large generating units ---- 129
    Cooling water ---- 130
    Footnotes to chapter 6 ---- 130
7. Economic considerations ---- 131
    Focus of the analysis ---- 131
    Costs and benefits: Discussion ---- 133
    Cost estimates ---- 137
    Evaluation of costs and benefits ---- 142
    Other analyses ---- 149
    Conclusions ---- 158
    Other economic factors ---- 159
    Other considerations ---- 160
    Footnotes to chapter 7 ---- 161
8. Regulatory consideration ---- 163
    Present regulation of the electric power industry ---- 163
    Regulatory issues ---- 165
    Regulating implications: An overview and some general conclusions ---- 187
    Conclusion ---- 191
    Footnotes to chapter 8 ---- 191
9. Additional studies ---- 193
    Load diversity ---- 193
    Reserves ---- 193
    Transmission ---- 194
    Economic considerations ---- 195
    Regulatory considerations ---- 196

Bibliography ---- 199

Glossary of abbreviations and definitions ---- 213

TABLES

3-1 Monthly load diversity among NERC (National Electric Reliability Council) regions 1970 ---- 40
3-2 Monthly load diversity among NERC regions 1971 ---- 41
3-3 Annual load diversity between NERC regions and groups of NERC regions 1970 ---- 42
3-4 Annual load diversity between NERC regions and groups of NERC regions 1971 ---- 43
3-5 Time-zone load diversity on the day of the U.S. coincident peak, 1962-71 ---- 52
3-6 Winter and summer coincident peakloads 1970-84 ---- 55
3-7 Annual load diversity as percentages of national noncoincident and coincident peakloads, 1962-71 ---- 56
3-8 Annual load diversity for the United States, 1962-71 ---- 58
3-9 Monthly and annual load diversity among NERC's estimated for 1975 (MW) ---- 61
3-10 Monthly and annual load diversity among NERC's estimated for 1976 (MW) ---- 62
3-11 Projected annual percentage increase in demand onpeak ---- 66
3-12 Annual peakload estimates and estimates of diversity by reliability council, 1980 and 1984 ---- 71
3-13 Low, medium, and high projections of annual peakloads and diversity, 1980 and 1981 ---- 72
3-14 Comparison of peakload growth scenarios by reliability council, 1980 and 1984 ---- 73
4-1 Growth of electric demand 1975-84 as projected by regional reliability councils April 1, 1975, contiguous United States ---- 92
4-2 Growth of generating capability 1975-84 as projected by regional reliability councils, April 1, 1975, contiguous United States ---- 93
4-3 Summary of operating reserves projected by regional reliability councils as of April 1, 1975, contiguous United States ---- 94
4-4 Projected generation reserves for the regional electric reliability councils (percent) contiguous United States ---- 95

Page
4–5 Savings due to a 1-percentage point reduction in reserves (United States) 97
4–6 Savings by reducing reserve levels to 15 percent in 1976 (United States) 98
7–1 Development of national indexes from Handy-Whitman 138
7–2 Cost estimate from selected sources 139
7–3 Overall cost estimates, 1975 dollars 140
7–4 Estimated regional generation plant construction costs, 1975 dollars 141
7–5 Regional generation plant construction costs and indexes 141
7–6 Summary comparison of estimated selected costs and benefits of a WUS–CUS EHV (extra-high-voltage) transmission interconnection, 1973 and 1975 146
7–7 Comparison of estimated selected costs and benefits of a Western U.S.-Central U.S. extra-high-voltage transmission interconnection 147
7–8 Levelized annual revenue requirements for various types of utilities WSCC AND MARCA 148
7–9 Estimated savings from accelerated reductions in operating reserves to 17.5 percent from 1975–84, by regional electric reliability council 153
7–10 Projected installed capacity and estimated savings from projected operating reserves, by regional electric reliability council, 1975–84 154
7–11 Weighted average coal/nuclear generation 1984 by reliability council region 155
7–12 Savings resulting from reducing operating reserves by selected amounts 156
7–13 Petroleum and natural gas savings 157
8–1 Federal organizations involved in the electric power industry 164

FIGURES

1–1 The general pattern of an electric power system 11
3–1 Typical load shape for peak load day, Pacific Northwest group area, winter 1975–76 26
3–2 Typical winter load shape, Pacific Northwest group area 27
3–3 A simple illustration using load diversity by balancing loads with opposing shapes over time 29
3–4 Illustration of generation capacity made available by seasonal load diversity 33
3–5 Time-zone hourly load data on day of U.S. winter peak in 1971 (December 22, 1971) 35
3–6 Time-zone hourly load data on day of U.S. summer and coincident peak in 1971 (August 10, 1971) 35
3–7 MAIN and MAPP areas 1980 estimated generating capacity, monthly peak loads and scheduled maintenance 37
3–8 SERC 1971 diversity with otner regional electric reliability councils 44
3–9 NPCC 1971 diversity with other regional electric reliability councils 45
3–10 MAAC diversity among regional electric reliability councils 46
3–11 ECAR diversity among regional electric reliability councils 47
3–12 MAIN diversity among regional electric reliability councils 48
3–13 SPP diversity among regional electric reliability councils 49
3–14 MARCA diversity among regional electric reliability councils 50
3–15 WSCC diversity among regional electric reliability councils 51
3–16 Load diversity as a percent of peak loads, 1962–71 57
3–17 Annual load diversity, 1962–71 59
3–18 Example of the objective of peakload management 67
4–1 Reserve requirement versus LOLP level desired 83
4–2 Forced outage reserve for hypothetical systems 84
4–3 Reserve requirement versus size of connected system 86
4–4 Forced outage reserve for hypothetical systems and selected sizes 87
4–5 Percent reserve requirement versus assumed standard deviation of load forecast 89
4–6 Effect of load factor on excess load probability 90
5–1 National electric reliability council transmission networks 111
5–2 Interregional ties 1974 112
5–3 Regional transmission interconnections with Canada and Mexico—1974 113
5–4 Interregional ties 1979 114
5–5 Interregional ties 1983–84 115
5–6 National Electric Reliability Council nonsimultaneous transfer capability and seasonal load diversity 118

APPENDIXES

Appendix I

"A National Power Grid System and The Environment" by Gary J. Pagliano, analyst in environmental policy, Environment and Natural Resources Policy Division, Congressional Research Service .... Page 229
  Powerplant facilities 230
    Land use 231
    Air quality 233
    Water quality and availability 234
    Radiological considerations 237
    Energy parks 237
  Transmission 239
    Land use 239
    Physiological effects 241
  Primary energy supply systems 242
    Land use 242
    Air and water quality 243
  National power grid implications 245
  Footnotes 248
"Legal Issues Relating to a National Power Grid" by Robert D. Poling, legislative attorney, American Law Division, Congressional Research Service 253
  Introduction 254
  Present Federal Power Commission jurisdiction 255
  Interconnection authority 256
  The Commerce clause 261
  Interstate compacts 263
  Antitrust law 264
  Federal chartered corporation 266
  State utility regulation 266
  Conclusion 267
  Footnotes 268

Appendix II

Comments by Interested Organizations

Letter from Alex Radin, general manager, American Public Power Association, to Senator Metcalf, December 31, 1975 273
Letter from W. Donham Crawford, president, Edison Electric Institute, with enclosed statement, to Senator Metcalf, February 17, 1976 276
Letter from Ken Holum, Ken Holum & Associates to Senator Metcalf, December 30, 1975 285
Letter from Robert O. Marritz, executive director and counsel, Missouri Basin Systems Group, with enclosed comments by Wayne Stafford, to Senator Metcalf, January 5, 1976 287
Letter from Robert D. Partridge, executive vice president and general manager, National Rural Electric Cooperative Association, to Senator Metcalf, March 3, 1976 296
Letter from W. E. Trommershausen, R. W. Beck and Associates, to Senator Metcalf, December 18, 1975 299

Appendix III

Text of S. 1208, National Electrical Energy Conservation Act of 1975, by Senators Metcalf, Abourezk, Hathaway, Humphrey, McGovern, Mansfield and Moss (companion bill to H.R. 5048, by Representatives Ottinger, Moss, Badillo, Wirth, Beard of Rhode Island and Moffett) 307

NATIONAL POWER GRID SYSTEM STUDY

An Overview of Economics, Regulatory, and Engineering Aspects

for

The Library of Congress
Congressional Research Service

CH2M HILL

November 1975

CH2M
HILL
engineers
planners
economists
scientists

14 November 1975

S9400.A0.09

Dr. Douglas N. Jones, Assistant Chief
Economics Division
Congressional Research Service
Library of Congress
Washington, D.C. 20540

Dear Dr. Jones:

Subject: Contract 75-22
A Study of National Power Grid System

This is the report of our national power grid system overview study. Our principal findings are presented in chapter 2, and a summary of the report precedes the main text.

In this study we have examined technical, economic, and regulatory aspects of a national power grid. Companion reports on the grid's environmental and legal aspects have been prepared by the Congressional Research Service's Environmental Policy Division and American Law Division.

We acknowledge with thanks the comments and suggestions of members of the CRS staff who reviewed the draft final report.

Thank you for the opportunity to participate in this study of national importance.

Sincerely,

Harold M. Mozer

Harold M. Mozer, P.E.
Director, Electrical Engineering

Lawrence F. Pinson

Lawrence F. Pinson
Project Economist

kf

PREFACE

This is the report of a study of a national power grid system, conducted for the Library of Congress Congressional Research Service by CH2M HILL. The study was undertaken in accordance with Congressional Research Service Contract No. 75-22, effective 1 June 1975.

Mr. Lee C. White, attorney and former chairman of the Federal Power Commission, and Mr. Allan J. Schultz, professional engineer and consultant on electric power system engineering and rate matters, served as special consultants to CH2M HILL for this study. Mr. White was especially concerned with the regulatory aspects and Mr. Schultz with the technical aspects of the national power grid.

SUMMARY

The idea of a national power grid system evokes a spectrum of notions as to its form, development, ownership, and regulation. Policy and action alternatives are wide-ranging: "Do nothing, the electric utility industry is doing fine" . . . "encourage development of stronger electric transmission networks generally within the present industry structure but with only a minimum of regulatory and institutional changes to overcome frustrations currently facing electric utilities" . . . "develop regional regulatory and operating agencies to plan, construct, and operate the nation's bulk power transmission systems" . . . "develop a Federal agency to plan, construct, and operate the nation's bulk power transmission systems."

It is within this framework of alternatives that this study examines the technical, economic, and environmental aspects of a national grid. It presents some findings and raises many issues needing further study before a national power grid policy can be developed. This is not a feasibility study, but an overview pointing the way to further examination of this important aspect of the national energy supply program.

There are now three separate power transmission networks that, together, serve essentially all of contiguous United States and parts of Canada and Mexico. One serves approximately the eastern half of the country, another serves Texas, and the third the western half of the country. There are no present plans to interconnect any of these networks, although various forms of interconnections have been studied.

Modern electric power transmission networks in the United States are both regional and partly national in scope. They have evolved from increasing numbers of interconnections among individual electric utilities and groups of utilities. Federal, investor-owned, publicly owned, and cooperatively owned utilities all derive economic and operating benefits from interconnected operation; however, many utilities, mostly smaller ones, still do not participate in these benefits.

The regional and multistate nature of electric transmission systems is a fundamental factor dominating national power grid considerations. We find, therefore, that if anything more than the "do nothing" alternative is undertaken, regulatory agencies and transmission-operating entities should be structured to provide multistate jurisdiction. There are significant regional differences influencing electric power system characteristics that must be respected in operating and regulating any form of a national grid system.

We can find no direct economic justification for an accelerated effort to construct a discrete national power grid superimposed over present and planned transmission systems. Major transmission system additions are now being planned to take advantage of the benefits of stronger interconnections among growing electric systems. Only if very large powerplants are constructed near the coal-rich areas of the west are major transmission lines connecting the eastern and western systems likely to be justified.

Largely because of seasonal differences, there is some regional diversity in electric load patterns. A part of this diversity is essential to permit the periodic removal of electric generators from service for maintenance; the remaining diversity can be used to permit interconnected utilities to share generating capacity and achieve savings in the amount of capacity that would be needed should each utility separately provide for its needs.

We find that present utility interconnections have sufficient capacity to capture essentially all the load diversity that exists among the major regional transmission networks. Further, transmission capacity planned for the future appears adequate to permit capture of any likely increase in load diversity. It is significant that, if present national policies directed toward energy and peakload management are successful, the load diversity, as a percent of the total load, is likely to decrease. Load diversity across the nation's time zones is too small, erratic in magnitude, and uncertain as to time of availability to be useful for planning any reductions in generation capacity.

While there are no identifiable long term barriers to the successful operation of a strong, high-capacity, fully coordinated national power network, for about the next 5 to 10 years the technology to enable this is uncertain. We expect the national grid to evolve whether or not a deliberate effort is made to accelerate its development.

If a full national power grid system could be developed, some relatively small reduction in the amount of generating capacity reserves carried by the nation's electric utilities may be possible. The effect of this lowered reserve level is not likely to permit a reduction in an average residential electric bill of more than about 3 percent. More studies are needed to determine definitively the relationship of a fully coordinated national grid to the nation's generation reserve needs.

With or without a national power grid system, the level of reserves maintained and the reliability objectives of the electric utility industry should be examined. Public evaluation of the effects and costs of changes in electric service reliability standards would be essential.

Important regulatory issues will be involved in virtually any future development of the nation's electric power transmission systems. Some expanded Federal role seems essential because of the increasing multistate activity of the electric power industry, but regional differences must always be respected. The Federal role can be limited to a regulatory one or can be that of the owner-operator, depending upon the national grid option selected. Under any option, the following regulatory issues are likely to be involved: authority to require participation, rate regulation, allocation of capital and operating costs, technical and physical considerations, environmental regulation, and wheeling of power.

Chapter 1
INTRODUCTION

WHAT IS IT?

What is a national power grid? This has not been defined uniformly. We find that a "national power grid" is perceived to be something different to various persons.

Probably the most common concept of a national power grid is a Federally owned and operated discrete network of high-capacity transmission lines overlaying the existing electric power systems of the United States, strongly tying together virtually all of the generating capacity and distribution utilities of the nation into a single, huge power supply system. A variation of this concept is ownership and operation of the national power network by a single non-Federal entity such as a nationwide transmission utility.

Another concept of a national power grid is based on functional characteristics and cannot be identified fully by discrete facilities. It is the conditions that would exist if and when the present trend toward more and stronger intercompany and interregional connections and coordinated operations reaches the stage where the power supply of virtually all of the nation's electric power systems is operated essentially as a single entity.

The proposed National Electric Energy Conservation Act of 1975 (S-1208 and HR-5048) would establish a number of regional bulk power supply corporations which cover the entire United States and a National Power Grid Corporation to establish and operate a national power grid system. In this proposed legislation, a national power grid system is defined as "consisting of electric power generating facilities, and a system of very high voltage transmission lines which, to the extent practicable, shall interconnect such generating facilities and the transmission systems of each regional corporation."

All concepts of a national power grid system assume that the nation's electric power systems would--in effect--receive the operational and economic benefits of a single, efficiently managed nationwide power system.

It is principally the functional aspects of the national power grid that we are concerned with in this report. Thus, our use of "national grid," "national power grid system," and similar terms is generally meant in the functional sense, unless, by context, specific facilities or specific forms of ownership are identified.

A POWER TRANSMISSION PRIMER

Electric power systems develop when and to the extent there is a desire by the public for electric energy. Based on forecasts of electric load, electric power generation facilities are planned and built.

Oftentimes the generating facilities are located many miles from the electric loads. Power transmission lines are then constructed to move bulk quantities of power to load center distribution points or receiving substations. From the receiving substations power distribution lines, usually having much lower capacity than the transmission lines, carry the power to individual residential, commercial, and industrial users. This general pattern of an electric power system is illustrated in figure 1-1.

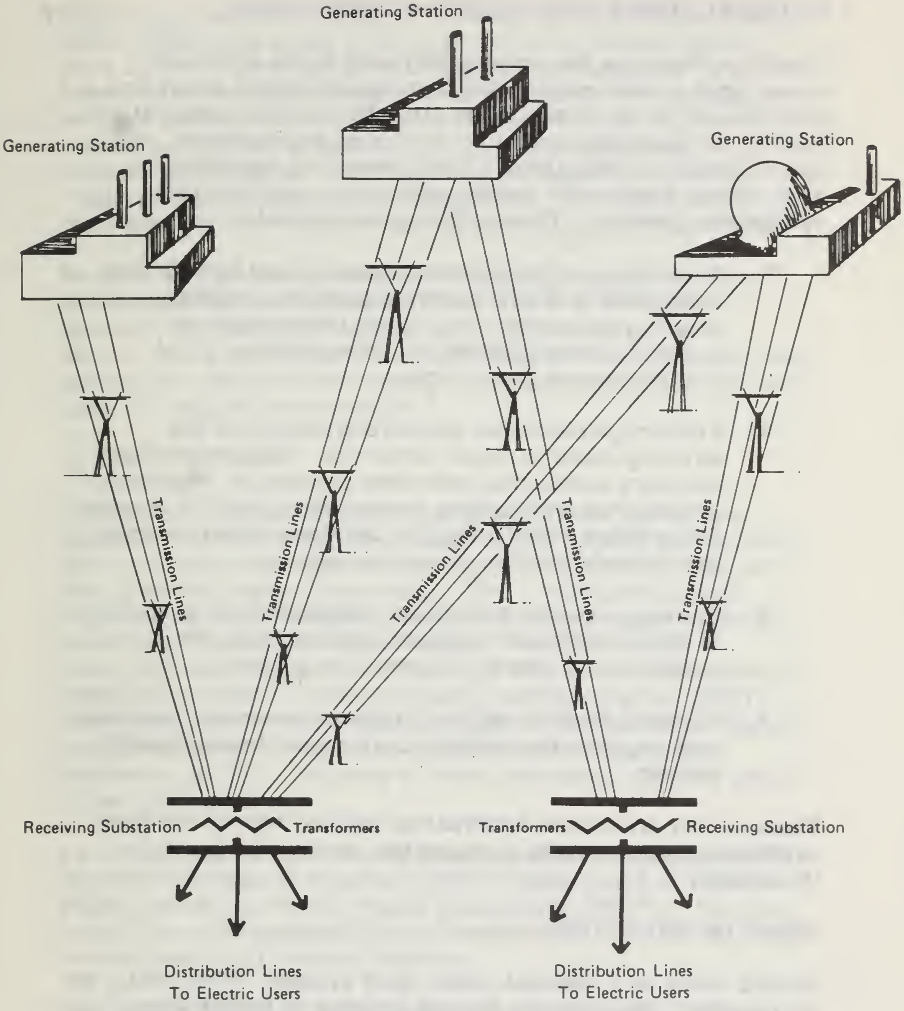
For many years the operators of electric power systems have known of benefits to be obtained from interconnecting two or more electric systems through transmission lines; therefore, many such interconnections have been built.

More recently, technology and economics have resulted in power generating units becoming larger, with many of the units supplying power to several different utilities. These joint-participation generating units require cooperation among the participating utilities in planning and operating the units.

To deliver power from the generating units, several transmission lines are required to interconnect the generating plant with the utilities sharing the power. The participating utilities, interconnected by transmission lines, coordinate their operations both to accomplish, and as a result of, joint participation in generating units.

Interconnected operations and interconnected transmission lines have evolved into local and regional powerpools and transmission networks. As benefits have been identified and subjected to limitations imposed by technical, institutional, regulatory, political, legal, and environmental considerations, many regional transmission networks have been interconnected.

If all of the nation's regional transmission networks were interconnected by high-capacity transmission lines, we would have a national power grid system. This system does not exist today. However, portions of what perhaps could become a national power grid system do exist and are providing substantial benefits.



THE GENERAL PATTERN OF AN
ELECTRIC POWER SYSTEM

Figure 1 - 1

NATIONAL POWER GRID SYSTEM ALTERNATIVES

Closely related are the various physical forms a national power grid system might take; a range of notions about how a grid should be developed, if at all; what utility, corporation, agency, or agencies should be its owner and operator; and how it should be regulated. This presents a spectrum of alternatives from which public policy on a national grid system can develop. These alternatives include:

- Do nothing. Considerable development has already been made and will continue toward a national power grid system, or at least three separate systems which together serve essentially all of the contiguous United States.

- Encourage extension and strengthening of the existing electric power networks. Government and industry leadership and some changes in regulatory procedures and statutes conceivably could overcome frustrations now facing the developers and users of the nation's electric power networks.

- Develop regional regulatory and operating agencies to plan, construct, operate, and regulate the nation's bulk power transmission system.

- Create a Federal agency to plan, construct, operate, and regulate the nation's bulk power transmission system.

These policy and action alternatives are the framework from which the reader should evaluate the issues addressed in this study.

SCOPE OF THE STUDY

Should there be a national power grid system? What would be its benefits? What are the factors adverse to establishing such a grid? How should a grid be built? Who should build and operate it? How should it be regulated? How far along are we toward having a national power grid?

We have examined economic, regulatory, and technical aspects of those questions and other issues relating to the creation of a national power grid system. This study is coordinated with a parallel effort by the Congressional Research Service American Law Division and Environmental Policy Division dealing with the legal and environmental issues involved in the creation of such a system.

This is not a feasibility study. Time and budget considerations have limited this study to an overview of a national power grid system. Some benefits of a grid are identified. We have identified other benefits that some perceive, but which we find don't exist. We have drawn upon and analyzed the extensive literature reporting on relevant aspects of a national power grid. We have brought together previous research and existing data, analyzed it, and interrelated the materials in a manner that has not previously been done.

We have suggested refinements in data gathering and also additional studies that should benefit efforts to control the costs of providing reliable electric service to the nation, while making prudent use of limited energy resources and minimizing the electric power industry's need to intrude upon the natural environment.

SOURCES OF DATA

This study is based largely on data published by Federal agencies. Publicly owned utilities and private organizations also provided important information. Principal sources are the: Federal Power Commission (FPC); National Electric Reliability Council (NERC) and the nine individual regional reliability councils; Edison Electric Institute (EEI); Electric Power Research Institute (EPRI); Nuclear Regulatory Commission (NRC); Federal Energy Administration (FEA); Bonneville Power Administration (BPA); and technical papers published by the Institute of Electrical and Electronics Engineers (IEEE). Sources of other published data are shown in the bibliography.

We communicated with the National Science Foundation (NSF), National Academy of Sciences (NAS), Department of Defense (DOD), American Public Power Association (APPA), National Association of Regulated Utility Commissioners (NARUC), and several operating electric utilities.

Most of the foregoing organizations are known and referred to in this report by their initials or acronyms.

Chapter 2
FINDINGS

LOAD DIVERSITY

There is very little usable load diversity among electric systems that is not already being utilized by existing interconnected systems. Much of the load diversity is used by electric utilities to permit planned generator outages for maintenance and for scheduled power interchanges. This situation is expected to continue as planned additional interconnections are implemented.

Diversity across time zones is too small, erratic in magnitude, and uncertain as to time of availability to be useful in planning any generation capacity reductions.

Nationally, load diversity as a percentage of the annual peakload is not likely to increase in the future. The diversity is essentially independent of the rate of load growth. However, most utilities are intensifying their efforts to improve (increase) their annual and daily load factors. This effort is strongly encouraged by the Federal Energy Administration (FEA). To the extent that load factors are increased, load diversity within an electric system and among systems will be reduced. By far the most comprehensive data on electric load diversity in the United States are those being maintained by the Edison Electric Institute.

RESERVES

Most utilities are now receiving substantial benefits in the form of lower reserve requirements as a result of interconnections and coordinated operations.

There have been no definitive studies of the effect of a fully coordinated, nationwide power system on the amount of generation reserve required to meet any reliability objective. At present there are no computer models sufficient to handle the enormous amount of data and calculating required in such a study. Furthermore, we found no studies incorporating statistical sampling.

Studies of large interconnected networks indicate that factors unrelated to interconnected transmission benefits tend to establish a lower limit on the desirable reserve level. This lower limit is near the level of reserves maintained now by the largest powerpools.

While a definitive study of reserve requirements of a national grid is not available, analysis of existing studies suggests that reserves might be reduced 1 to 3 percentage points as a result of a strong national power grid without reduction of present standards of reliability.

Significant reductions could be made in the amount of installed generation capability if overall electric system reliability levels are reduced. However, we could find evidence of only preliminary studies of the factors involved in such an overall reduction of reliability objectives. These factors include: (1) establishment of reliability priorities for selected loads; (2) methods to physically protect service to higher priority loads; (3) quantifying the effects of various levels of reliability as may be applied to segments of the load; and (4) public acceptance of the results.

TRANSMISSION

Electric utility systems in the eastern, midwestern, and southern portions of the contiguous United States are now effectively interconnected and their operations coordinated to obtain a large measure of pooling benefits. The interconnected network is comprised of the electric systems of seven of the nine electric reliability councils of the nation and parts of eastern Canada. The two areas not so interconnected are those of the Electric Reliability Council of Texas (ERCOT) and the Western Systems Coordinating Council (WSCC).

The electric systems of ERCOT are effectively coordinated among themselves, but have no normally operating interconnections with other systems in the United States.

The electric systems of WSCC, which serve about 51 percent of the land area of the contiguous United States and British Columbia, are effectively coordinated among themselves. Interconnections between WSCC utilities and Mid-Continent Area Reliability Coordination Agreement (MARCA) utilities have been operational in the past. As the systems have grown, however, the interties have become relatively weak to the extent that interconnected operation with present facilities is not technically possible.

Recently, most utilities have tended toward joint planning, financing, and operating of major powerplant and transmission facilities. As a result, powerpooling has become an increasingly important aspect of electric utility operations. There are compelling reasons for this trend. Among these are growing incentives to build large and costly power projects. These projects, encouraging multiple participation, increase regulatory restraints and compulsions, environmental impacts, and economic stringencies.

With the exception of the Far West systems and the Texas systems already noted, the electric utility systems in the contiguous states will be, for practical purposes, fully interconnected within the next decade. With the motivations arising out of policy, contractual, regulatory, and related influences, utility operations will be coordinated to seek optimum achievement in economy, reliability, and energy saving. Moreover, there will continue to be effective coordination with many electric utilities in Canada and some coordination with utilities in northern Mexico.

Regional interconnections--involving long, extra-high-voltage (EHV) transmission lines--should each be treated on its own merits based on its total net benefits.

With foreseeable technology, a nationwide extra-high-voltage grid superimposed on the existing transmission systems would be very costly and in other respects less attractive than the transmission network that is now evolving. Experience has demonstrated that such an evolved network, properly patterned and designed for optimum achievement of inter- and intraregional benefits, has the flexibility of meeting load growth with minimum advance expenditure.

Diminished fuel reserves have made utilities reluctant to use scarce supplies, at any cost. This reluctance seems likely to lessen opportunities for interregional power transfers.

Wheeling is a useful technique to reduce power transmission costs, avoid unnecessary duplication of facilities, and provide access to distant power supplies for smaller utilities. However, it should not be imposed upon a utility without careful technical study of its effects.

Effective interconnection between the now separately operating systems of the Far West and the Midwest, under existing or now-planned conditions, would entail one or more transmission lines, each at least 1,500 miles long. If the interconnection were alternating current, the equivalent of at least two 765-kV circuits would be required; the annual cost of such a facility would far outweigh its benefits. If the interconnection were direct current, one 800-kV (400±-kV) circuit would suffice for some years; the net benefits from such a facility appear marginal, but warrant additional study. However, such a study also should evaluate the benefits of additional Pacific Northwest-Pacific Southwest interconnections and interconnections between the Midwest United States and Canada. These benefits may have more merit than, and may preempt, benefits of a Far West-Midwest interconnection.

The pessimistic appraisal of a Far West-Midwest interconnection would be reversed if one or more large power-generating centers were developed in the coal-rich West to serve loads in both the Midwest and Far West. Firm power could then be supplied to the Far West and Midwest, with the added feature that any diversity power could be swung in either direction, in the interest of overall economy. In like fashion, spare generating capacity in either region could be made available for use in the other region, and economy energy could be interchanged. If it is assumed that the costs of the transmission lines from a new generating center are chargeable to the delivery of firm power, which they might well be, the interconnection's benefits to the two major regions would be procured as an essentially zero-cost byproduct.

A Federal Power Commission study in 1972 found that there would be a net economic benefit to an interconnection between Electric Reliability Council of Texas (ERCOT) interconnected systems and the interconnected systems of the Southwest Power Pool (SPP). An ERCOT technical committee review of the FPC report concluded that the interconnection would be detrimental from both reliability and economic standpoints. The utilities in the ERCOT and SPP areas do not appear to have any future plans to develop the interconnection suggested by the FPC.

The distances between the major load areas of ERCOT and SPP are relatively short as contrasted with the very long distances involved when considering interconnections between the Midwest and Far West.

ECONOMIC ASPECTS

From our revision of the economic analysis included in the *Report of the Western United States - Central United States Study of Transmission Interconnection,* December 1973, we find that there still are not sufficient benefits to be derived from an east-west interconnection to presently justify further study or allocation of funds for construction of an alternating current (ac) tie. However, a preliminary benefit/cost analysis suggests that a more detailed examination of a direct current (dc) tie might prove fruitful. Additional studies of this east-west interconnection should also consider possibly superior and mutually exclusive benefits from strengthening north-south interconnections in the central and western regions.

The FPC *Study of Proposed Interconnection between Electric Reliability Council of Texas and Southwest Power Pool* concluded that in 1972 there were ample potential savings of reserves and operating costs to justify detailed study of full interconnection of ERCOT with SPP. Based on the relatively short distances involved; recent increases in the cost of capital; the nation's emphasis on reducing consumption of petroleum and natural gas through substitution of coal-, hydro-, and nuclear-based electricity; and widespread efforts to improve system load factors, we believe that there is even greater reason now than in 1972 to do a detailed analysis of the feasibility of this particular interregional interconnection.

In our assessment of the savings that could be achieved by reducing operating reserves, we found that for each 1-percentage point reduction from 1975 levels of operating reserves the nation could realize a present value of capital savings over 10 years of $3.16 to $3.22 billion. Reducing reserves to a level of 15 percent of projected annual peak demand would yield total present value savings over 10 years of $20.1 to $20.5 billion. Reducing reserves to 17.5 percent of peak demand would yield present value savings over 10 years of $9.4 to $9.6 billion in addition to that already planned.

If reserves are reduced to 17.5 percent, the annual cost saving of $1.3 billion would reduce the nation's electric revenue requirements and, therefore, rates about 3 percent, based on 1974 data. When allocated to residential customers on an energy-usage basis, the average residential household would realize an annual savings of $6.10. Not included in these estimates is the present value of savings from reduced operation and maintenance costs. The overall savings represent the amounts that would not have to be spent for generation reserves; however, any costs associated with additional transmission lines needed, or reduced reliability that might result to obtain the reduced reserves, would have to be deducted to obtain the net savings.

At approximately $325,000 per mile of 765-kV ac, single-circuit, these estimated additional savings of operating reserves would allow, as an alternate investment in the U.S. bulk power industry, approximately 26,000 miles of EHV transmission lines to be built. In this analysis allowance is included for the costs of substations, switching stations, and line compensation, communication, and control equipment, but not for the specific placement of these lines. A major transmission system planning study, well beyond the scope of this study, would be needed to determine more easily how many miles of lines and the number of substations and other facilities that would be desirable. However, R. J. Ringlee and J. W. Beck pointed out in *An Assessment of Policies and Technical Factors Affecting the Degree of Interconnection of*

Electric Utilities in the U.S. (table IV-1) that approximately 44 interregional transmission ties of 345 kV and above are being planned by all segments of the electric power industry by 1992 to firmly interconnect every regional reliability council except ERCOT. Further, Ringlee and Beck estimated (table VI-5) that with a medium-load growth rate and concentration of baseload, fossil-fired generation at mine-mouth locations, some 114,400 miles of additional transmission lines of 345 kV and above would be needed in the United States between the years 1973 and 2000.

In summary, a reduction in capital expenditures for generating equipment having a present value of about $10 billion could be achieved with a reduction in generation reserves to a national average of 17.5 percent. Before deducting any costs that would be required to obtain these savings, we find the amount saved would average $6.10 per year residential user of electricity.

We cannot determine within the scope of this study how or whether such a reduction in reserves can be obtained. It is significant that, while we estimate the savings that might be obtained from a reduction in reserves would support construction of about 26,000 miles of EHV and UHV transmission lines, the utility industry will probably need to construct nearly four times that mileage of transmission lines between 1973 and 2000. The transmission system being planned should be directed toward obtaining all economic benefits that are technically possible and we expect, generally, that this will be the case. We see no direct economic justification for an accelerated effort to construct a discrete national power grid superimposed over the present and planned systems.

REGULATORY CONSIDERATIONS

The electric utility industry is regulated in various ways at local, state, and national levels. Responsibility for regulation is diffuse, and jurisdictional conflicts arise. In fact, actions of local and state regulatory agencies have sometimes hampered the full development of regional transmission and generation projects.

Increasing interconnection and powerpooling activity of electric utilities indicates a need for regulation based on a broader jurisdiction than a single state. Regional regulatory agencies, or strengthened Federal regulatory authority, preempting local and state authority for regional and multiregional utility operations should be explored. However, important regional differences influencing power system characteristics must be respected in the consideration of regulatory restructuring.

Consideration should be given to forming additional regional entities to finance, build, and operate generation and transmission projects. Such entities could both aid in and result from further development toward a national power grid.

The desirability of strengthening the Federal Power Commission's jurisdiction over interstate power transfers should be examined in the light of increasing power interchange activity.

The legal authority of the Federal Power Commission to compel wheeling needs to be readdressed. Objectives of a national power grid might be furthered if the Federal Power Commission had authority both to require wheeling and to require that facilities be planned and constructed to permit wheeling where technical studies show wheeling to be desirable.

Regulatory and legal problems are likely if reliability standards are reduced or different reliability standards are applied to various classes of customers in order to reduce reserve requirements.

Evidence is conflicting regarding the influence of regulation on the rate of technological innovation. This issue needs attention in any consideration of the relationship of regulation to increased power interchange activities and a national power grid.

Environmental regulation is closely involved with implementation of a national grid and intermediate steps toward regional interconnections. Environmental concerns both motivate and hamper aspects of interconnection. Multiple authority at local, state, and national levels complicates the problem.

Although most utilities in the United States have achieved the benefits of strong interconnected system operation, many utilities--mostly smaller ones--still do not share these benefits. Many smaller utilities have, with some success, been seeking relief in the courts and regulatory agencies through antitrust laws and antitrust reviews associated with nuclear powerplant licensing procedures. A national power grid operated by a Federal agency or other publicly oriented entity could provide powerpooling benefits to these smaller utilities.

A national power grid would likely stimulate questions regarding the equity of the Federal power supply preference benefits, the tax and interest rate cost differentials, and freedom from some regulation enjoyed by publicly owned utilities. These are long-standing arguments that also raise questions of tax benefits given to investor-owned utilities and the effectiveness of some regulatory agencies.

TECHNOLOGICAL QUESTIONS

On a short-term basis, about 5 to 10 years, technology is too uncertain to assure successful operation of a strong, high-capacity, fully coordinated national power network consisting of a discrete system of EHV and UHV transmission lines and associated terminal and control facilities.

Control systems for such a network have not been fully developed.

Concerns have been expressed over the possible biological effects of UHV transmission, and this aspect is under study.

A larger and more strongly connected system suggests the desirability of larger generating units, perhaps in the 1,500- to 2,000-MW range. Units of these sizes have not been developed. Also, at present there appears to be a tradeoff between the benefits of economy-of-scale and expected lower reliability of large generating units.

Lack of cooling water may hamper development of otherwise desirable energy resources in the coal-rich areas of the West and Southwest.

Extensive use of direct current transmission will be dependent on successful development of a direct current circuit breaker.

Cryogenic and superconducting techniques for power transmission have considerable long-term promise to lower cost and lessen the environmental impact of high-capacity electric energy transmission.

There are no identifiable long-term barriers to a fully coordinated national power grid network. We expect such a grid to evolve whether or not a deliberate effort is made to accelerate its development.

Most technological areas important to improved transmission networks, such as UHV insulation requirements, development of direct current circuit breakers, analysis of UHV biological effects, etc., are under study.

ADDITIONAL STUDIES

From our limited scope study we have identified several areas where additional studies would be useful to analysis of a national grid and, perhaps as important, to general improvements in planning and operation of the nation's electric utility systems. These studies include:

- Continuation of Edison Electric Institute's ongoing load-diversity studies.
- Studies in detail of how utilities use load diversity.
- Development of improved techniques for forecasting load growth and load diversity.
- Development of computer techniques and statistical methods for analyzing the generation reserve requirements on systems as large as the entire United States.
- Studies of reliability standards and the ramifications of using the same or different reliability standards for different classes of customers.
- Intensify efforts to improve the reliability of generating facilities.
- A definitive study of interconnections between ERCOT and SPP.
- A definitive study of a high-capacity direct current (dc) interconnection between WSCC and MARCA taking into account alternatives, including additional north-south ties in WSCC and in MARCA that might preempt benefits of a WSCC-MARCA tie.
- Studies of alternative condenser cooling methods in water-short areas with abundant fuel resources.
- Several studies suggested in chapter 7 of economic factors in the electric utility industry. These relate to scale economies, price-demand relationships, financing, load forecasting, and load management techniques, interrelationships among electricity and alternative energy forms at point of use, quantification of external costs, and the benefits and costs of regulatory processes.
- Comprehensive studies leading to elimination of overlap and duplication in regulatory processes.
- Studies to establish regulatory processes to resolve local, state, and regional conflicts between energy needs and environmental concerns.

- Studies of possible extension of regulation to alternative energy resources not now regulated.

- Studies of regulatory agency staffing and training alternatives to avoid instances of regulatory commissions' submission to the interests of the regulated to the detriment of the public interest.

- Studies of improved methods of data collection and storage and data access. Duplication of effort must be avoided.

- Studies of methods to make regulation more responsive to needs of increasing regional and multistate interconnections and powerpooling. In this context, some form of regional or strengthened Federal regulatory agencies should be considered.

Chapter 3
LOAD DIVERSITY

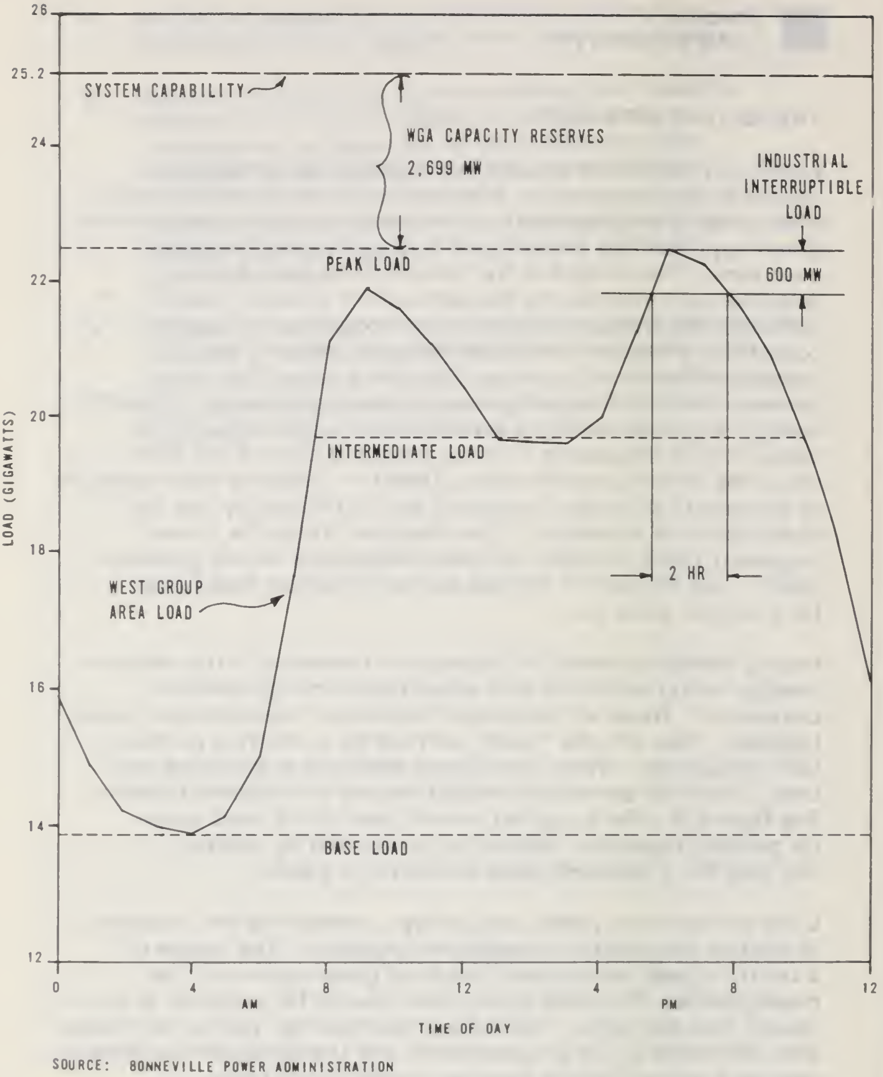
THE NATURE OF LOADS

Electricity suppliers or utilities measure the amount of customer requirements in kilowatts and hourly increments. When displayed graphically, the consumer requirements for a given supplier can be pictured as a curve that fluctuates over time. The height of the curve (kilowatts) for any selected hour represents the demand for electric energy. It indicates the amount of electricity production equipment (capability) needed during the selected hour to supply customers' electricity needs. The area under the curve between hour markings represents the total amount of electric energy supplied during a selected hour. The measure of demand is in thousands of watts supplied during the hour--thus, the term "kilowatt-hours (kWh)." Because the magnitude of demand is so large, measures are facilitated by the use of multiples of kilowatts. One thousand kilowatts is one megawatt (MW) and one thousand megawatts is one gigawatt (GW). See figure 3-1 for one system's typical load shape for a winter peak day.

Hourly demand varies in intensity in response to the electric-energy-using activities and established energy uses of customers. When all individual customers' demands are taken together, they are the "load" carried by a utility's production equipment. When customers' demands are plotted over time, it will be seen that demand occurs in repeated patterns. See figure 3-2 for a typical winter peak week load shape. Its general repetitive pattern is illustrated by plotting the load for a selected week in each of 3 years.

Load curves have peaks and valleys, indicating the intensity of load on the utility's production capacity. The shape of a utility's load curve over time is of great concern to its management. The load at any time should be supplied at the lowest cost possible. The lowest-cost energy can be produced and delivered by large generation and transmission equipment operated at its efficient level on a continuous basis. Demand occurring continuously is known as "baseload;" the large, efficient equipment designed to serve that load is "baseload plant."

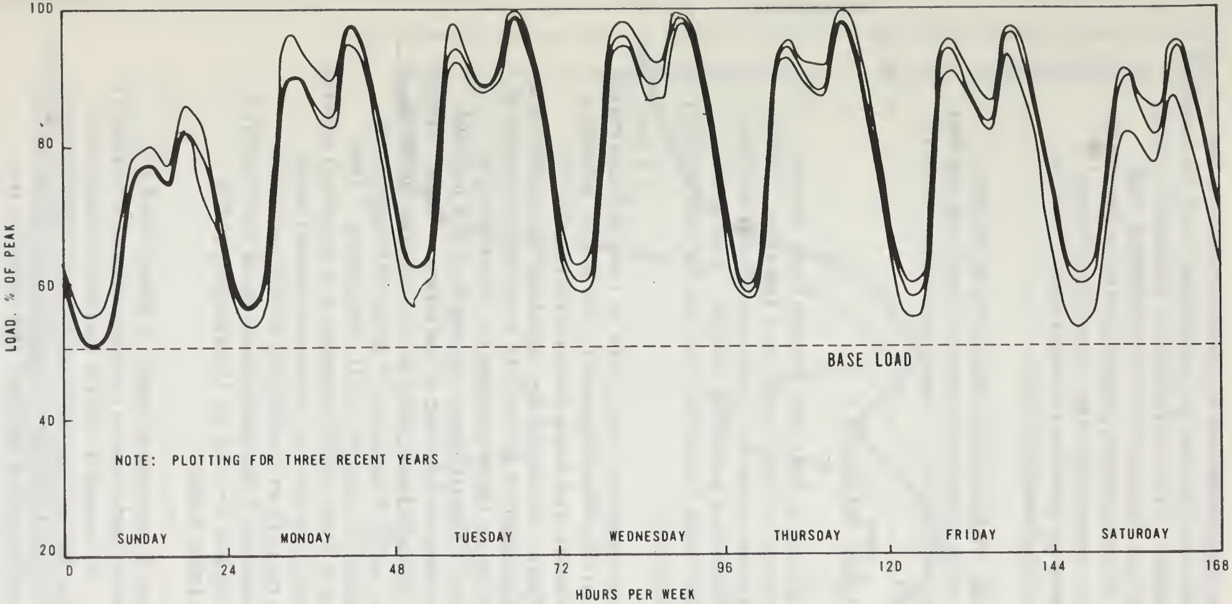
Loads that occur in large amounts for relatively long periods, but not continuously, are intermediate loads. The sharp and intensive demand substantially greater than the average load is known as peakload. Generally, peak demand has a relatively short duration. Intermediate loads are served by baseload and intermediate load plants, and peakloads are served by peaking plants.



SOURCE: BONNEVILLE POWER ADMINISTRATION

TYPICAL LOAD SHAPE FOR PEAK LOAD DAY,
PACIFIC NORTHWEST WEST GROUP AREA,
WINTER 1975 - 1976

Figure 3 - 1



SOURCE: BONNEVILLE POWER ADMINISTRATION

TYPICAL WINTER LOAD SHAPE
(Hourly Loads as Percent of Weekly Peak),
PACIFIC NORTHWEST GROUP AREA

Figure 3 - 2

Figure 3 - 2

The short duration peakloads are of great concern to the power industry because the energy demanded must be supplied by peaking equipment. This equipment is generally not as expensive to install as baseload and intermediate load equipment, but it is considerably more costly in the other input requirements, especially fuel, resulting in total costs per unit of energy supplied being higher than for either baseload or intermediate plant.

This is of particular interest now that costs of oil and natural gas have risen relative to costs of coal and nuclear fuel, and now that availability of these petroleum fuels is becoming uncertain.

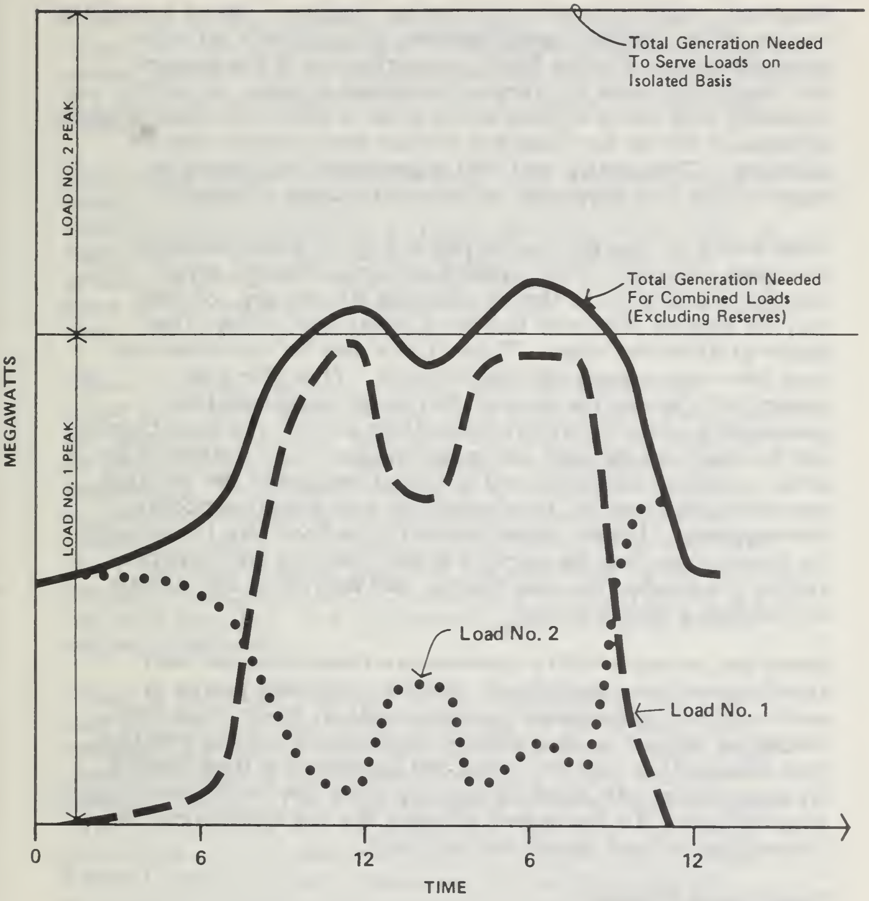
THE NATURE OF LOAD DIVERSITY

A desirable objective is to hold the overall cost of each unit of energy supplied to the lowest cost possible. One method of holding down costs is to serve as much load as possible from the efficient baseload plants. The most economically served load is one that can be served entirely from baseload equipment.

Individual customer demands vary both in time of occurrence and intensity. A utility's management, therefore, attempts to find and serve loads that have peaks which occur in patterns that alternate, allowing the baseload equipment and intermediate load equipment to operate over longer spans of time. This balancing of loads results in a flattening of the total load curve. The different patterns of the individual peakload occurrences are load diversities. Thus, within a single electric utility's load there are individual demand diversities which, when "captured," allow efficiencies of operations that result in benefit to all consumers. The peaks and valleys of individual demands are balanced against each other, allowing the utility to use equipment more efficiently. This results in producing energy at costs lower than are possible if the individual loads were served separately. See figure 3-3 for an illustration of the diversity of individual loads.

That which is true of individual loads is also true for groups or classes of loads having similar characteristics in their occurrence. An electric utility can balance a group of loads having one set of characteristics with other groups having different characteristics. As additional loads with differing characteristics are served, the shape of the utility's load curve changes, equipment is operated more efficiently, and power supplied is less expensive.

During a single day a utility will be able to capture certain load diversity occurring within the area it serves.



A SIMPLE ILLUSTRATION USING LOAD DIVERSITY BY BALANCING LOADS WITH OPPOSING SHAPES OVER TIME

Figure 3 - 3

However, much diversity may not be captured. Work schedules, variances in weather, and lifestyles of customers all influence the patterns of the hourly occurrences of the demand for electricity made by various customer groups. A utility normally will serve a geographic area in which the determinants of demand for its services are similar and occur in similar patterns. That utility will find it desirable to capture as much of the load diversity in its service area as possible.

That which is true for one utility is true in great measure for other utilities. Two utilities serving adjacent areas may have load curves that are shaped differently, or they may be shaped similarly but have peaks and valleys that occur at different times. Thus, there may be considerable load diversity among several utilities. This offers an opportunity to realize savings in capital investment for generating capacity and in production costs. The opportunity can be realized through two major means. One method is to effect a formal corporate and physical merger of the utilities. An alternative method is to establish a cooperative pooling arrangement. Under either method, the diversity is captured by interconnecting the service areas, pooling and synchronizing the production operations, and operating the supply systems as a single entity.

When two or more utility systems are interconnected and their operations coordinated, the more efficient plants in each system are operated to serve loads in other areas that would be served by less efficient equipment without pooling. In a cooperative pool the costs and benefits are then shared in accordance with some formula by all of the pool's participating utilities. To the extent systems are not interconnected, diversities in load cannot be captured.

Short-Term Diversity

Short-term load diversity occurs during a single day or a small number of days. This diversity is normally captured on a short-term operating basis. If several systems are merged or pooled and operated as an integrated system, the capture of much short-term diversity is more or less automatic. Some short-term diversity can be captured even if systems operations are not fully integrated. For example, when one utility finds that it has extra baseload capability because a particular demand or load has been reduced, the power dispatcher telephones utilities with which it is interconnected and offers the excess capability for service. If one or more of the other utilities has higher cost capability than that offered, the excess capability will be taken, and the savings in costs will be divided between the supplier and the receiver. Such interutility exchanges and sales may occur for several days or several hours in a day or may occur for only a few minutes. The length of time that the power transfer occurs is determined by whether the savings are acceptably larger than any costs allocated to the interchange.

Short-term diversity offers savings from the interchange or sale of "economy energy" on an operational basis. This requires interconnections and open communication lines, at least. Short-term load diversity can be captured to a greater extent by full interconnection and integrated operations of the systems in a cooperative pool, a holding company pool, or a fully merged system.

There are many degrees of integration of operations; generally, the greater the degree of integration, the greater the amount of available load diversity that can be captured. At the present levels of development in management and technology, the greatest degree of operational integration is achieved through full interconnection and centralized dispatch of power. Although the capture of diversity on a short-term basis makes possible the realization of economies through management and scheduling of existing plant, it does not make possible, to a significant extent, savings in new capital investment.

There is no official measure of the magnitude of short-term load diversity in the United States nor of the amount now captured and sold or interchanged by utilities. Such interchanges and sales are common practices in the electric utility industry. The interchanges are netted against each other. Data about the magnitude and volume of the gross exchanges are not reported to any data-compiling agency. The net values of short-time diversity interchanges are included in industry reports with the data reported on power purchased by utilities during a year under contractual arrangements and under emergency conditions. Thus, the amount of power interchanged and sold for "economy energy" cannot currently be determined.

Few rigorous studies of diversity have been made. However, the most comprehensive study to date made no attempt to measure hourly, daily, or other short-term diversity.[1]

Seasonal Diversity

Load diversity, as it affects capacity planning between utilities, is defined as the difference between (1) the sum of the independent, or separate, peakloads of two or more load areas for any given period, and (2) the coincident peakload of the combined areas within a particular time period.[2] The diversity is usually expressed in kilowatts (kW) or kilowatt-hours when integrated over an hour of time.

---

[1] See footnote references, end of chapter.

Customers' demands for electric energy recur in patterns with some degree of regularity, although they do not recur in any predictably precise way. As we have noted, short-term diversity--hour-to-hour, day-to-day, and weekday-to-weekend changes in demand--is captured through short-term operational coordination. Long-term or seasonal diversity, sometimes referred to as annual diversity, allows for system planning to minimize capacity investment.

Seasonal diversity usually results from a marked and consistent difference in weather and significant regional differences in the price and availability of alternate energy sources. Examples of electricity uses that are strongly influenced by weather are air-conditioning, irrigation, and space heating. When one system's load peaks in winter and another system's load peaks in summer, the time difference of the peaks provides a seasonal diversity that allows coordinated planning of generation to achieve reduced investment. The generation capacity a system has available for diversity interchange during its offpeak season is limited to the capacity available over and above that required for maintenance purposes, reserves, and serving load. This is illustrated on figure 3-4 and discussed in more detail later in this chapter.

Annual or seasonal diversity within the Western Systems Coordinating Council (WSCC) region, for example, provides the basis for power transfers between the winter-peaking Pacific Northwest and the summer-peaking Pacific Southwest.[3] Similarly, the seasonal diversity between the TVA and the SPP allows a large planned interchange of power. The TVA area, a subregion of the Southeast Electric Reliability Council, has a winter heating peakload. The Southwest Power Pool has a summer air-conditioning peakload.

The large difference between the winter and summer peak demands in the Electric Reliability Council of Texas (ERCOT) area results in large generating surpluses during the winter. ERCOT is not interconnected to other regions. It has no appreciable hydroelectric capability. Therefore, its reserves are required by reliability standards to be somewhat higher than needed by other regions that have interconnections, power sales interchange agreements, and hydroelectric capacity.[4]

Although seasonal load diversity affords an opportunity for capital savings through reducing installed generating capacity requirements, its realization requires that the diversity be predictable and that commitment to a decision to capture

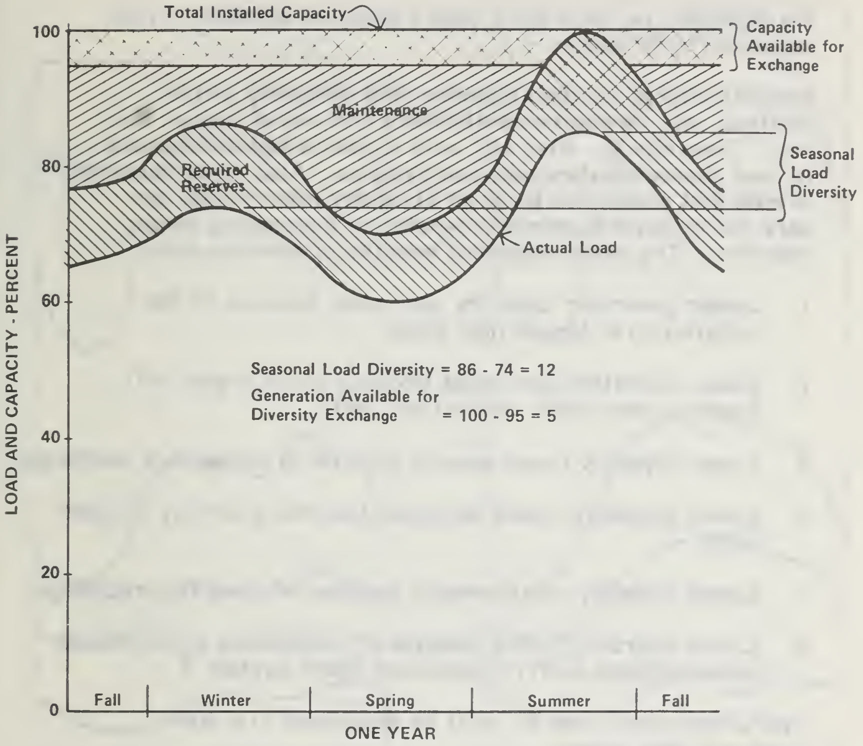


ILLUSTRATION OF GENERATION CAPACITY MADE AVAILABLE BY SEASONAL LOAD DIVERSITY

Figure 3 - 4

the diversity be made more than 3 years in advance of new capacity requirements.[5]

Benefits offered by the existence load diversity can be realized only through establishment and use of system interties. Diversity is, after all, only a measure of differences in load characteristics between systems. Also, it is important to note that economies through diversity interchange are only one of several primary benefits of developing strong interties. The more important benefits of interties are:

1. Lower generator-capacity unit costs because of the installation of larger unit sizes.

2. Lower operating unit costs because of the higher efficiencies associated with larger units.

3. Lower capacity requirements because of emergency exchange.

4. Lower operating costs because of economy energy transactions.

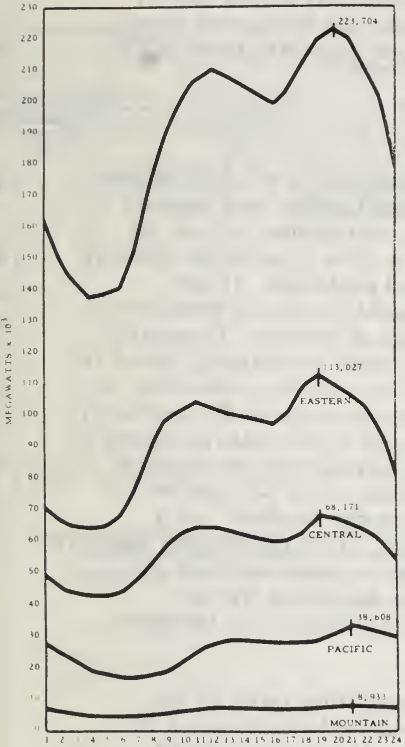
5. Lower capacity requirements because of diversity exchange.

6. Lower operating costs because of integrating predominant hydrosystems with predominant steam system.[6]

Interconnections, per se, will be discussed in a later section of this report.

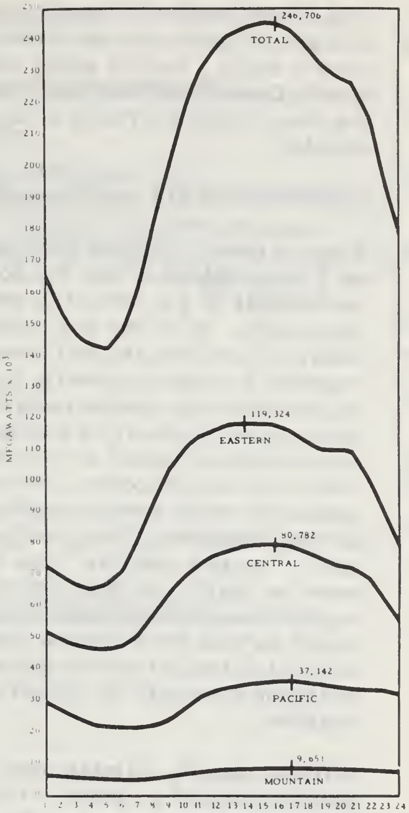
Time Zone Diversity

"The hour-by-hour load curves of individual power systems have considerable similarity in time and shape."[7] See figures 3-5 and 3-6. "Nevertheless, even with similar patterns the peak demands do not occur coincidentally in the nation's four time zones. . . . To the extent that the coincident load for systems in each time zone tends to peak sharply at approximately the same time of day, by local time, a load diversity occurs between time zones."[8] Without an analysis of loads and how they occur across the nation, it would seem reasonable to believe that investment in some generating capacity could be foregone "through east-west exchanges of power to take advantage of this time zone diversity. . . . Through east-west interconnections across time-zone boundaries, the leading and lagging time-zone systems could render capacity assistance to the zone at peak."[9] However, the *a priori* notions about time-zone diversity are not borne out by the data of this study.



TIME - ZONE HOURLY LOAD DATA ON DAY OF U.S. WINTER PEAK IN 1971. (Dec. 22, 1971)

Figure 3 - 5



TIME - ZONE HOURLY LOAD DATA ON DAY OF U. S. SUMMER AND COINCIDENT PEAK IN 1971. (Aug. 10, 1971)

Figure 3 - 6

Source: Ten - Year Report on Load Diversity Based on 1962 - 1971 Data, Edison Electric Institute. New York, N.Y.

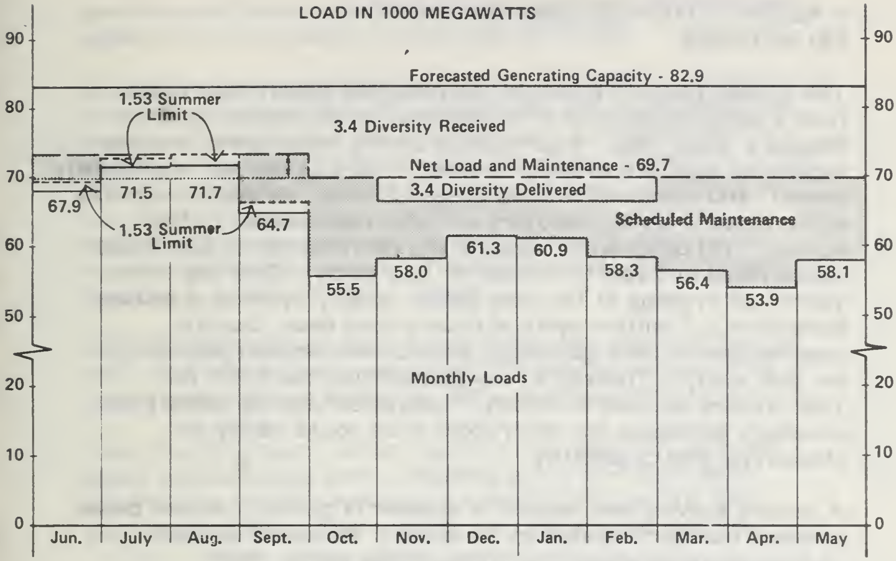
Figure 3 - 5
Figure 3 - 6

The determination of time-zone or rolling diversity requires analysis of loads and the pattern of their occurrence on an hourly basis. Such a study was conducted for the EEI by Utility Consulting Services. More will be discussed about the observed occurrence of time-zone diversity later in this chapter.

Maintenance and Load Diversity

Electric power systems must be capable of providing service as it is called for under the operating, price, and demand constraints of the market in which each system serves its consumers. A utility will attempt to have generation capacity ready for serving the full, expected peakload. It will maintain a reserve capacity to provide service if some part of the operating system is forced out of service. Generally when capacity planning and load growth forecasting suffer no serious impairments, a system will be able to accomplish its load/reserves objective. All available equipment is normally needed to serve annual peakloads and to provide necessary system reserves. Then, as loads decline from the annual peak, "excess capacity" may be taken out of service and reserve standby so that maintenance can be done, as it normally is, during offpeak seasons. This generating capacity out of service for maintenance must be deducted from the calculated load diversity figures to determine the net available diversity for sharing installed capacity between systems.

Utilities usually maintain major generating units on an annual planned schedule. Little planned maintenance is scheduled during the 2 to 5 months of the peak seasons. With only 7 to 10 months available, an average of 10 to 15 percent of a utility's generating capacity can be expected to be out of service for planned maintenance throughout the offpeak months. The schedule for maintenance is carefully tailored to conform to changes in loads. As loads increase toward the annual peaks, machines are brought off maintenance into service. As loads decline, generators and other equipment are taken out of service or reserve standby to allow annual maintenance. Most systems schedule generator maintenance so that the total capacity of machines in service, on reserves, and under maintenance remains nearly constant (see figure 3-7). Therefore, load diversity representing less than about 10 percent of a system's or a region's total generating capacity before allowance is made for maintenance will be reduced virtually to zero after allowance is made for maintenance.



Source: Western Systems Coordinating Council (WSCC), Mid Continent Area Power Planners (MAPP), Mid-America Inter-Pool Network (MAIN) and East Reliability Agreement (ECAR), July 1969, An Appraisal of Transmission Study 190.

M.A.I.N. AND M.A.P.P. AREAS
1980 ESTIMATED GENERATING CAPACITY,
MONTHLY PEAK LOADS
AND SCHEDULED MAINTENANCE

Figure 3 - 7

A RECENT STUDY OF LOAD DIVERSITY - EEI METHODS

The Edison Electric Institute has collected hourly load data from a large proportion of the systems of the electric power industry since 1962. Represented among the electric systems supplying data are investor-owned, federally owned, municipally owned, and consumer-owned systems; thus, all major segments of the electric utility industry are well represented in the survey. All geographic regions are represented except ERCOT, which made no reports of data for this study. Over the 10 years, an average of 158 bulk power supply systems supplied more than 1.3 million units of hourly load data. Such a comprehensive data-gathering project was beyond possibility for this study. Therefore, we decided that the EEI's *Ten-Year Report on Load Diversity*[10] would be used as a basis for diversity estimates for this report if we could verify its objectivity and credibility.

A sample survey was made of a number of publicly owned power systems that participated in the study. We asked officials in these systems about their roles in the study, their knowledge of its conduct, and the data that they supplied. None of the utilities surveyed indicated any knowledge of or suspicion that the data furnished were in any way mishandled. The data provided to EEI were simply hourly load readings punched into computer cards. Some utilities we queried commented that the data furnished to EEI was the identical data used by that utility for its planning studies. There was no reason for the study to be questioned by the utilities surveyed.

The data were processed by an independent computer vendor and the results furnished to EEI for interpretation and publication. The textual materials were produced by EEI, while the data collection and processing were accomplished without direct EEI participation. Even the preparation of the data collection program was done by the independent computer vendor. This program is spelled out in a procedures booklet in which detailed instructions about data preparation are given.[11] We read and analyzed these instructions for built-in bias in the design of the data-gathering program. None of significance was found.[12]

Three further checks on the study's credibility were made. We asked the computer vendor about the form of data receipt, storage, processing, and access by organizations other than the vendor. Only the vendor and EEI Subcommittee on Load Diversity had access to the data banks, and the data could be released to no one prior to a minimum of processing to adhere to standard disclosure prohibitions. Any agency or person could have comprehensive output from the data once approval for processing was approved by EEI.

Several Federal agencies, FEA, FPC, and NSF, were asked to provide opinions of this EEI study. An FPC representative said that it was by far the best and most accurate piece of empirical work ever done on load diversity in the U.S. The FPC recommended that the EEI study be used as a basis for our diversity analysis since FPC hourly load data are limited to 3 weeks per year, weeks that only approximate summer and winter peaks. The EEI material was recommended because it produced actual peaks.

The FEA informed us that it uses some data supplied by the EEI. The NSF also has employed EEI data in certain of its recent programs on modeling of the energy sector of the U.S.

From the EEI report, actual dates of peakloads in selected study regions were then compared to the monthly peaks reported by electric reliability councils for regions that were comparable. The monthly correlation was perfect.

In reviewing other studies of specific interconnections, we found that other research projects have used data supplied through the cooperation of EEI. For example, *An Appraisal of Transmission Study 190*[13] and *Report of the Western U.S.-Central U.S. Study of Transmission Interconnection*,[14] both carefully formulated and comprehensive studies, used EEI load diversity data.

Based on this assessment, we concluded that not only are the EEI data used for this study the best available but also they are usable at a satisfactory level. Therefore, *The Ten-Year Study on Load Diversity* was chosen as the basis for determining rates of change in load diversity and its stability over time, and levels of the interregional load diversity. Measures of these types were to be applied to data from other sources to obtain estimates of future diversity.

EEI gave us permission to use its computer vendor's EEI data bank. CH2M HILL formulated the requirements and requested that the data be processed to provide measures of diversity for 1970 and 1971 on a regional electric reliability council basis because that is the geographic basis chosen for this study. The results of these special computer runs are presented in tables 3-1, 3-2, 3-3, and 3-4. Graphic displays of the 1971 diversity data, which compare the latest available data on actual interregional load diversity are shown on figures 3-8 through 3-15. These graphics emphasize the size and seasonal occurrence of load diversity. However, it

Table 3-1. MONTHLY LOAD DIVERSITY AMONG NERC REGIONS 1970

Month	Noncoincident Peak (MW)	Coincident Peak (MW)	Coincident Time Day/Hr	Diversity (MW)
Jan	223,706	216,831	8/20	6,875
Feb	213,009	205,634	4/20	7,375
Mar	200,553	192,761	16/12	7,792
Apr	199,273	190,895	29/14	8,378
May	207,884	202,022	22/15	5,862
Jun	235,333	222,636	30/16	12,697
Jul	242,132	233,488	29/14	8,644
Aug	239,099	229,501	14/14	9,598
Sep	232,865	218,886	4/14	13,979
Oct	202,615	192,317	26/19	10,298
Nov	223,118	214,514	24/20	8,604
Dec	224,141	213,934	16/20	10,207

Annual Load Diversity Among NERC Regions

Noncoincident Peak = 246,285 MW
Coincident Peak = 233,488 MW 29 July; 2:00 p.m.

Diversity = 12,797 MW
Diversity = 5.2% of the sum of noncoincidental peakloads
Diversity = 5.5% of coincidental peakloads

SOURCE: Utility Consulting Services and Edison Electric Institute.

Table 3-2. MONTHLY LOAD DIVERSITY AMONG NERC REGIONS 1971

Month	Noncoincident Peak (MW)	Coincident Peak (MW)	Coincident Time Day/Hr	Diversity (MW)
Jan	231,545	219,473	19/20	12,072
Feb	228,290	220,233	1/20	8,057
Mar	216,874	208,765	8/12	3,109
Apr	205,045	197,838	6/21	7,207
May	207,637	200,237	19/14	7,400
Jun	251,141	240,798	28/14	10,343
Jul	250,777	236,520	8/16	14,257
Aug	251,482	246,706	10/16	4,776
Sep	250,272	242,127	8/16	8,145
Oct	225,340	214,643	1/14	10,697
Nov	227,773	219,821	23/19	7,952
Dec	236,114	223,704	22/20	12,410

Annual Load Diversity Among NERC Regions

Noncoincident Peak = 261,075 MW
Coincident Peak = 246,706 MW 10 August; 4:00 p.m.

Diversity = 14,369 MW
Diversity = 5.5% of the sum of noncoincidental peakloads
Diversity = 5.8% of coincidental peakloads

SOURCE: Utility Consulting Services and Edison Electric Institute.

Table 3-3. ANNUAL LOAD DIVERSITY BETWEEN NERC REGIONS AND GROUPS OF NERC REGIONS 1970

	MARCA WSCC	SPP WSCC	SPP MARCA	MAIN MARCA	MAIN SPP	SERC SPP	ECAR MAIN	ECAR SERC	MAAC ECAR	NPCC MAAC	WSCC	MARCA	SPP	MAIN	SERC	ECAR	MAAC
NPCC	2,617	2,995	2,551	2,727	2,816	2,409	2,771	2,106	1,525	-0-	2,539	1,801	2,886	2,551	2,927	2,006	1,497
MAAC	2,561	1,521	1,627	835	1,627	1,804	1,026	887	-0-	-0-	3,440	298	1,697	678	1,673	531	
ECAR	2,293	1,942	835	311	956	2,037	-0-	-0-	-0-	559	2,425	132	1,179	311	1,571		
SERC	3,393	1,453	660	1,786	2,073	-0-	2,841	-0-	1,927	2,268	4,131	556	1,105	1,887			
MAIN	2,519	640	153	-0-	-0-	1,191	-0-	1,581	806	1,054	3,653	139	223				
SPP	2,756	-0-	-0-	497	-0-	-0-	868	1,571	1,915	2,284	3,478	483					
MARCA	-0-	719	-0-	-0-	413	38	139	934	315	432	1,441						
WSCC	-0-	-0-	3,714	3,821	3,895	3,826	4,738	5,203	5,142	4,281							
NPCC MAAC	3,402	2,466	2,474	1,230	2,795	2,501	1,274	1,201	-0-								
MAAC ECAR	4,209	3,088	2,105	982	2,331	2,132	-0-	-0-									
ECAR SERC	4,336	2,514	1,761	1,967	1,923	-0-	-0-										
ECAR MAIN	3,436	1,859	524	-0-	-0-	2,301											
SERC SPP	2,875	1,148	-0-	1,268	-0-												
MAIN SPP	2,761	-0-	-0-	-0-													
MAIN MARCA	-0-	808	-0-														
SPP MARCA	-0-	-0-															
SPP WSCC	-0-																

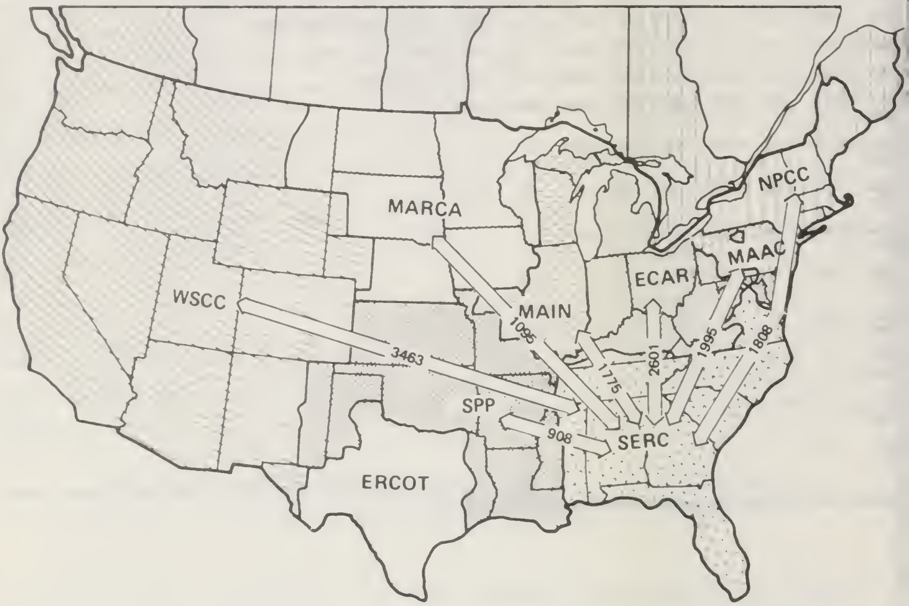
SOURCE: Utility Consulting Services and Edison Electric Institute.

Table 3-4. ANNUAL LOAD DIVERSITY BETWEEN NERC REGIONS AND GROUPS OF NERC REGIONS 1971

	MARCA WSCC	SPP WSCC	SPP MARCA	MAIN MARCA	MAIN SPP	SERC SPP	ECAR MAIN	ECAR SERC	MAAC ECAR	NPCC MAAC	WSCC	MARCA	SPP	MAIN	SERC	ECAR	MAAC
NPCC	3,014	1,996	3,203	2,902	1,834	3,530	2,909	2,246	1,144	-0-	3,764	1,676	3,304	2,059	1,808	2,223	127
MAAC	2,849	1,924	2,841	2,893	1,745	3,225	2,847	2,184	-0-	-0-	3,692	1,724	2,423	1,898	1,995	2,161	
ECAR	5,387	4,341	1,484	229	293	4,102	-0-	-0-	-0-	3,178	5,387	171	2,620	229	2,601		
SERC	2,392	1,172	1,879	2,143	1,919	-0-	2,390	-0-	2,624	2,767	3,463	1,095	908	1,775			
MAIN	3,150	2,774	1,202	-0-	-0-	3,338	-0-	18	915	2,496	4,154	93	2,327				
SPP	4,675	-0-	-0-	2,338	-0-	-0-	2,391	2,409	3,352	4,209	4,378	1,229					
MARCA	-0-	1,729	-0-	-0-	104	2,200	93	111	897	2,236	1,432						
WSCC	-0-	-0-	4,878	4,489	4,825	4,642	7,557	4,676	4,775	4,464							
NPCC MAAC	4,111	2,696	4,059	3,615	3,178	4,469	3,864	3,201	-0-								
MAAC ECAR	4,422	3,007	2,216	961	1,025	4,083	-0-	-0-									
ECAR SERC	4,323	2,908	1,273	18	82	-0-	-0-										
ECAR MAIN	6,629	5,789	1,255	-0-	-0-	3,873											
SERC SPP	4,957	791	-0-	3,500	-0-												
MAIN SPP	4,310	-0-	-0-	-0-													
MAIN MARCA	-0-	3,598	-0-														
SPP MARCA	-0-	-0-															
SPP WSCC	-0-																

SOURCE: Utility Consulting Services and Edison Electric Institue.

ECAR	East Central Area Reliability Coordination Agreement
MAIN	Mid-America Interpool Network
MAAC	Mid-Atlantic Area Council
MARCA	Mid-Continent Area Reliability Coordination Agreement
NPCC	Northeast Power Coordinating Council
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
ERCOT	Electric Reliability Council of Texas
WSCC	Western Systems Coordinating Council



SERC
1971 DIVERSITY 1/ WITH OTHER REGIONAL
ELECTRIC RELIABILITY COUNCILS

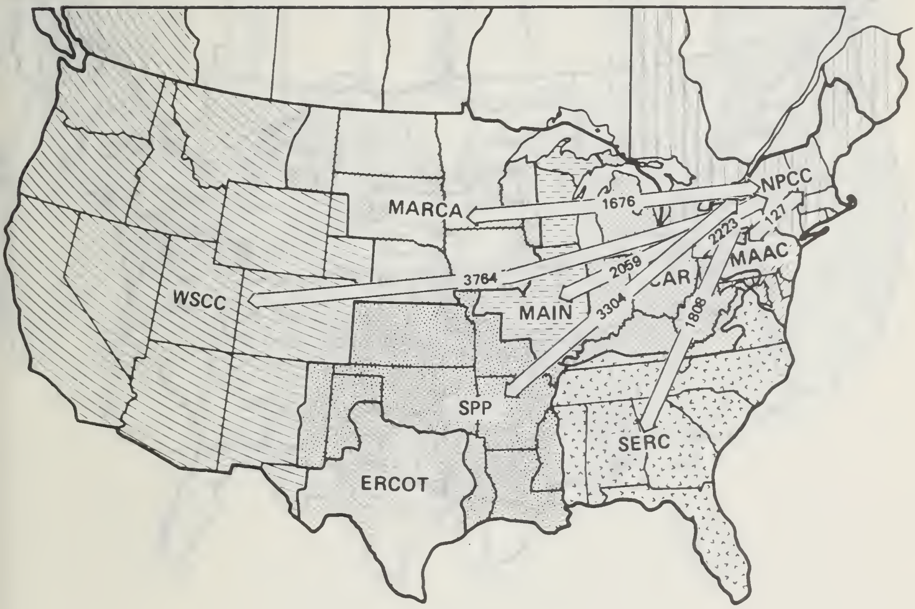
Source: Table 3-4

1/ BEFORE MAINTENANCE

Note. Diversity is calculated between
two reliability regions,
therefore the data are not additive.

Figure 3

ECAR	- East Central Area Reliability Coordination Agreement
MAIN	- Mid-America Interpool Network
MAAC	- Mid-Atlantic Area Council
MARCA	- Mid-Continent Area Reliability Coordination Agreement
NPCC	- Northeast Power Coordinating Council
SERC	- Southeastern Electric Reliability Council
SPP	- Southwest Power Pool
ERCOT	- Electric Reliability Council of Texas
WSCC	- Western Systems Coordinating Council



NPCC
1971 DIVERSITY 1/ WITH OTHER REGIONAL
ELECTRIC RELIABILITY COUNCILS

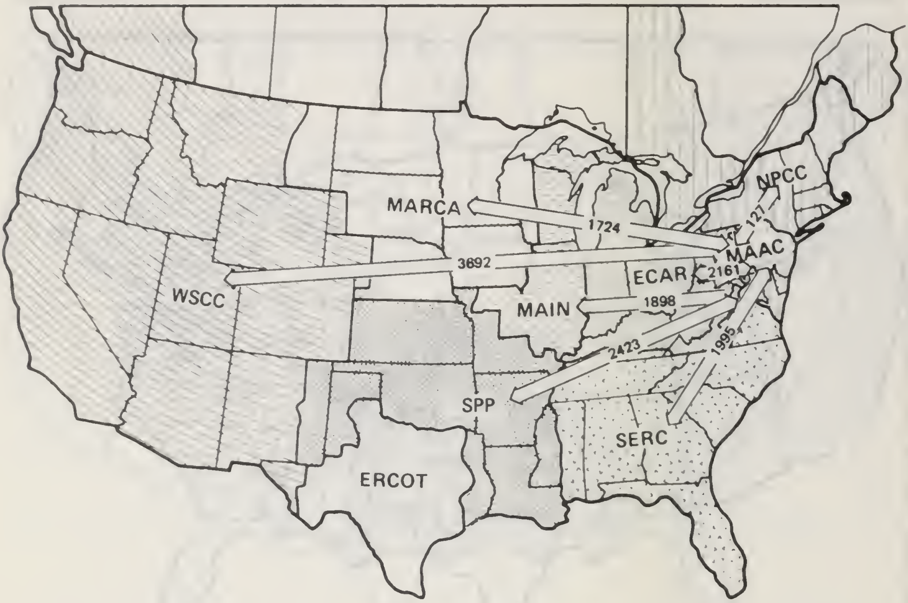
Source: Table 3-4

1/ BEFORE MAINTENANCE

Note: Diversity is calculated between two reliability regions, therefore tha data are not additive.

Figure 3-9

ECAR	- East Central Area Reliability Coordination Agreement	NPCC	- Northeast Power Coordinating Council
MAIN	- Mid-America Interpool Network	SERC	- Southeastern Electric Reliability Council
MAAC	- Mid-Atlantic Area Council	SPP	- Southwest Power Pool
MARCA	- Mid-Continent Area Reliability Coordination Agreement	ERCOT	- Electric Reliability Council of Texas
		WSCC	- Western Systems Coordinating Council



MAAC
DIVERSITY AMONG REGIONAL
ELECTRIC RELIABILITY COUNCILS 1/

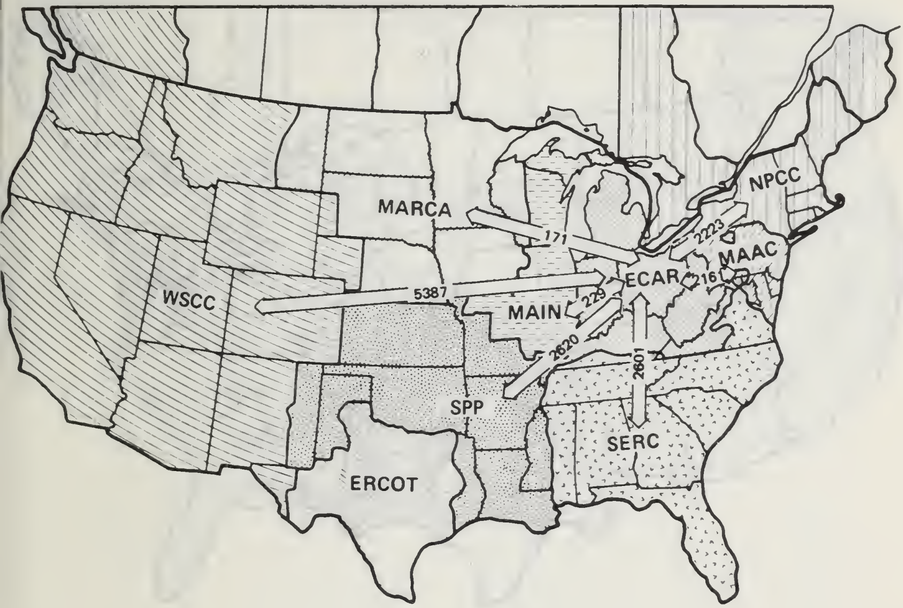
Source: Table 3-4

1/ BEFORE MAINTENANCE

Note: Diversity is calculated between two reliability regions, therefore the data are not additive.

Figure 3 -

ECAR	- East Central Area Reliability Coordination Agreement
MAIN	- Mid-America Interpool Network
MAAC	- Mid-Atlantic Area Council
MARCA	- Mid-Continent Area Reliability Coordination Agreement
NPCC	- Northeast Power Coordinating Council
SERC	- Southeastern Electric Reliability Council
SPP	- Southwest Power Pool
ERCOT	- Electric Reliability Council of Texas
WSCC	- Western Systems Coordinatin Council



ECAR
DIVERSITY AMONG REGIONAL
ELECTRIC RELIABILITY COUNCILS [1]

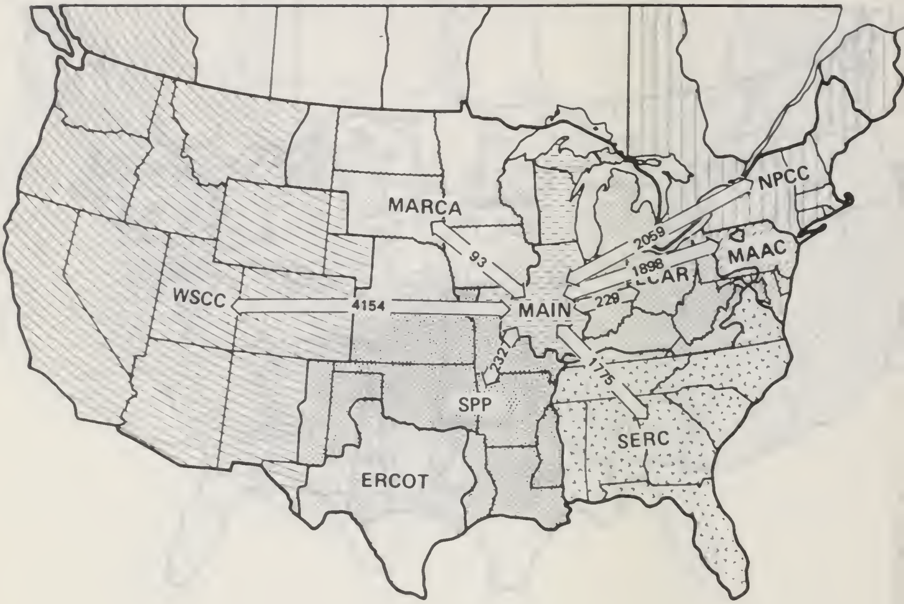
Source: Table 3-4

[1] BEFORE MAINTENANCE

Note: Diversity is calculated between two reliability regions, therefore the data are not additive.

Figure 3 - 11

ECAR	- East Central Area Reliability Coordination Agreement
MAIN	- Mid-America Interpool Network
MAAC	- Mid-Atlantic Area Council
MARCA	- Mid-Continent Area Reliability Coordination Agreement
NPCC	- Northeast Power Coordinating Council
SERC	- Southeastern Electric Reliability Council
SPP	- Southwest Power Pool
ERCOT	- Electric Reliability Council of Texas
WSCC	- Western Systems Coordinating Council



MAIN
DIVERSITY AMONG REGIONAL
ELECTRIC RELIABILITY COUNCILS 1/

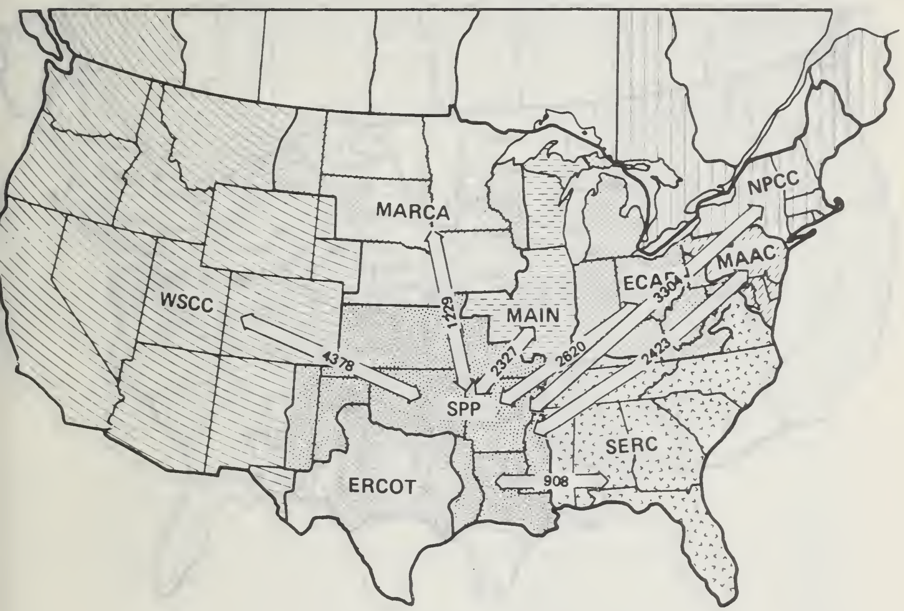
Source: Table 3-4

1/ BEFORE MAINTENANCE.

Note: Diversity is calculated between two reliability regions, therefore the data are not additive.

Figure 3

ECAR	- East Central Area Reliability Coordination Agreement
MAIN	- Mid-America Interpool Network
MAAC	- Mid-Atlantic Area Council
MARCA	- Mid-Continent Area Reliability Coordination Agreement
NPCC	- Northeast Power Coordinating Council
SERC	- Southeastern Electric Reliability Council
SPP	- Southwest Power Pool
ERCOT	- Electric Reliability Council of Texas
WSCC	- Western Systems Coordinating Council



SPP
DIVERSITY AMONG REGIONAL
ELECTRIC RELIABILITY COUNCILS 1/

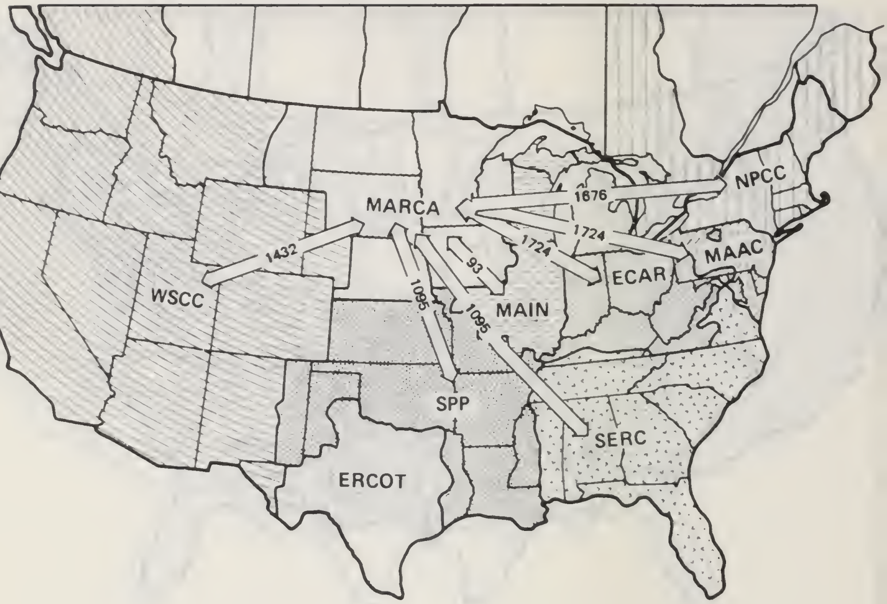
Source: Table 3-4

1/ BEFORE MAINTENANCE

Note: Diversity is calculated between two reliability regions, therefore the data are not additive.

Figure 3 - 13

ECAR	- East Central Area Reliability Coordination Agreement
MAIN	- Mid-America Interpool Network
MAAC	- Mid-Atlantic Area Council
MARCA	- Mid-Continent Area Reliability Coordination Agreement
NPCC	- Northeast Power Coordinating Council
SERC	- Southeastern Electric Reliability Council
SPP	- Southwest Power Pool
ERCOT	- Electric Reliability Council of Texas
WSCC	- Western Systems Coordinating Council



MARCA
DIVERSITY AMONG REGIONAL
ELECTRIC RELIABILITY COUNCILS 1/

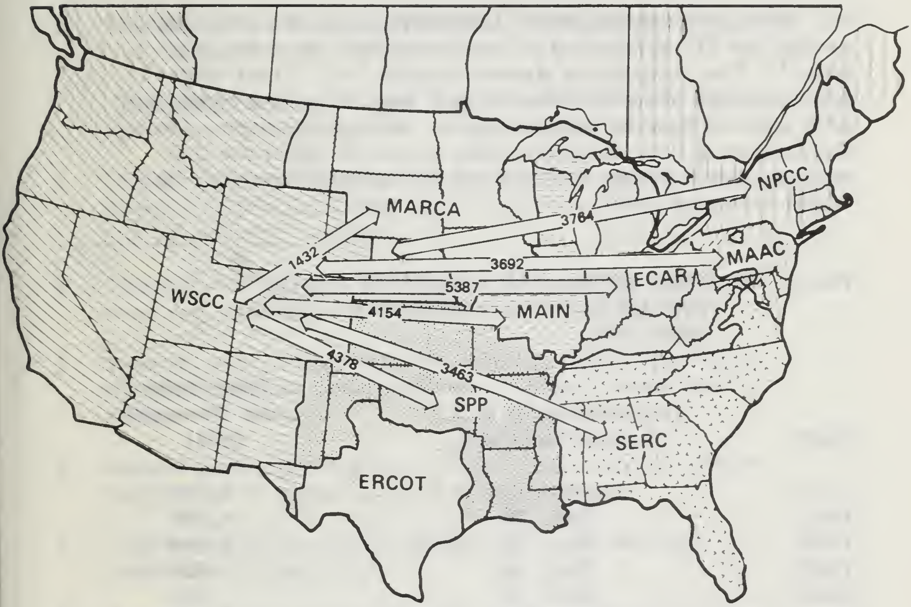
Source: Table 3-4

1/ BEFORE MAINTENANCE

Note: Diversity is calculated between
two reliability regions,
therefore the data are not additive.

Figure 3 -

ECAR	- East Central Area Reliability Coordination Agreement
MAIN	- Mid-America Interpool Network
MAAC	- Mid-Atlantic Area Reliability Coordination Agreement
MARCA	- Mid-Continent Area Reliability Coordination Agreement
NPCC	- Northeast Power Coordinating Council
SERC	- Southeastern Electric Reliability Council
SPP	- Southwest Power Pool
ERCOT	- Electric Reliability Council of Texas
WSCC	- Western Systems Coordinating Council



WSCC
DIVERSITY AMONG REGIONAL
ELECTRIC RELIABILITY COUNCILS 1/

Source: Table 3-4

1/ BEFORE MAINTENANCE

Note: Diversity is calculated between two reliability regions, therefore the data are not additive.

Figure 3 - 15

should be especially noted that the interregional annual diversity figures were not adjusted to account for generator maintenance. Allowance for maintenance, as shown on figure 3-6, reduces the generating capacity made available by diversity. Maintenance data for 1971 were not collected for this study.

Time-Zone Diversity

For *The Ten-Year Report on Load Diversity*, the computer vendor for EEI conducted a time-zone analysis of the load data.[15] The results are shown in table 3-5. The trend appears to be toward a smaller total amount year by year but with wide variations in some years. A significant drop in the amount of time-zone diversity occurred when the U.S. shifted from a winter to a summer annual peakload-day between 1964 and 1965.

Table 3-5. TIME-ZONE LOAD DIVERSITY ON THE DAY OF THE U.S. COINCIDENT PEAK, 1962-1971

Year	Occurrence of U.S. Coincident Peak	Time-Zone Load Diversity (MW)
1962	Dec. 12	5,280
1963	Dec. 18	4,268
1964	Dec. 18	4,094
1965	Aug. 16	556
1966	July 12	642
1967	July 24	1,467
1968	Aug. 23	1,363
1969	July 16	263
1970	July 29	2,472
1971	Aug. 8	193

SOURCE: *Ten-Year Report on Load Diversity, Based on 1962-1971 Load Data*, EEI, New York.

The total loads occurring in each time zone at the time of the nation's winter and summer coincident peaks for 1971 are plotted in reference to eastern standard time on figures 3-4 and 3-5. While the time-zone peaks do not occur simultaneously, the spread across time is quite narrow. If the entire load shape is considered, there is little diversity over the whole time range of the occurrence of individual peaks.

> "Even without considering the transmission and complex dispatching required to utilize time-zone diversity, it is apparent that load diversity due to difference in clock time can contribute very little toward capacity planning."[16]

In analyzing the EEI study[17] to determine its usefulness for this study, several important characteristics were noted.

1. The absolute amount of diversity in MW in the continental U.S. is apparently increasing.
2. The annual amount of load diversity is a smaller percentage of total peakloads year by year. See table 3-7.
3. The occurrence and magnitude of load diversity are difficult to predict using conventional data analysis and forecasting methods.
4. The amount of load diversity varies by large amounts from region to region and from year to year.
5. Year by year, additional FPC power supply areas find that their annual peakloads have shifted from winter to summer.
6. Annual peakloads are occurring in the summer in more northern FPC power supply areas each year.
7. There is little time-zone diversity across the four time zones of the U.S.
8. As of 1971, the electric power industry in the U.S. for the 7 preceding years had a summer peak. Looking at the regional distribution of seasonal peakloads shows only the TVA and NPCC areas, Colorado, the Pacific Northwest, Montana, and the Dakotas had winter annual peaks by 1971.

In addition to the above observations of the full *Ten-Year Report*, the following comments apply to the results obtained by the special run of 1970 and 1971 raw load data:

1. The load diversity for the 2-year period is highly unpredictable from month to month.
2. Between and among regions, load diversity is widely scattered with relatively small amounts in individual locations.

Considerations of More Recent Influences

The data from regional electric reliability council reports indicate that a continuation of the summer peak trend is expected at least through 1985. (See table 3-6.) If this does occur,[18] interregional seasonal diversity will be of little or no value as a basis for system planning and development. The only diversity that would be of value to the industry would be that which yields economy energy interchanges--the production of energy on a short-term basis by a low-cost producer for sale to another producer whose best alternative for the power production would cost more. The savings are normally split between producer and purchaser, holding down the overall costs of both.

The FEA has instituted a series of programs on a broad front to encourage utilities' conservation of energy through load management.[19] The objective is to reduce the nation's dependence on oil and natural gas for fulfilling its energy needs. Conceivably, these programs, electricity rate reform,[20,21] and changes in relative prices and availability of oil, gas, and electricity, could cause a resurgence in the demand for electric heat,[22] independent of utilities promoting its use. In Great Britain, lower rates for the offpeak use of electricity have prompted the use of electricity for heating. To take advantage of the offpeak rates, various types of heat storage units have been developed.

If such influences and innovations become commonplace in the U.S., winter peaks may again develop in the northern half of the country. Because of the use of air-conditioning, summer peaks are likely to continue in the southern half of the country. If the research efforts of ERDA into development and application of solar heating are successful, this probably will result in widespread winter heating with solar power in the southern tiers of states and particularly in the Southwest.

If such developments occur, there possibly will be ample summer/winter diversity on a north-south basis to justify strengthening existing interconnections.

CURRENT AND FUTURE LOAD DIVERSITY

Trends of Load Diversity

From *The Ten-Year Report on Load Diversity* and from the special computer run of EEI hourly load data done for CH2M HILL by Utility Consulting Services, we made estimates of load diversity trends. Annual load diversity on a national basis was calculated as percentages of the sum of noncoincident peakloads and of coincident peakloads. The percentages are

Table 3-6. WINTER AND SUMMER COINCIDENT PEAKLOADS
1970-1984

Year	ECAR		ERCOT[1]		MAAC		MAIN		MARCA		NPCC		SERC		SPP		WSCC	
	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Actual[2]																		
1970	41,743	40,926	NA	NA	23,938	20,944	23,089	19,261	9,693	8,759	26,857	28,220	50,514	49,996	22,810	15,774	44,044	46,278
1971	45,552	42,520	NA	NA	25,629	21,771	24,874	20,070	10,136	9,188	28,968	28,682	51,861	50,128	24,562	17,052	47,011	49,493
Projected[3]																		
1975	55,682	52,999	25,273	17,694	31,930	26,710	31,863	24,859	14,300	13,103	33,761	33,276	78,947	77,264	34,735	24,398	64,822	64,940
1976	60,321	57,582	27,552	19,336	33,670	28,290	33,926	26,582	15,341	14,323	35,563	35,117	85,816	84,130	37,526	26,388	68,917	69,116
1977	64,787	61,550	30,102	20,453	35,670	30,040	36,767	28,321	16,750	15,523	37,536	37,086	93,596	90,709	41,012	28,694	73,611	73,735
1978	69,217	65,613	32,649	22,238	37,710	31,850	39,258	30,137	17,901	16,749	39,414	39,056	101,042	97,685	44,262	31,054	78,593	78,572
1979	73,656	69,809	35,320	24,176	39,710	33,640	41,826	32,054	19,037	17,802	41,437	41,142	108,973	105,252	47,978	33,744	82,975	82,924
1980	78,313	74,109	38,114	26,103	41,780	35,570	44,557	34,077	20,212	18,876	43,462	43,516	117,288	112,818	51,960	36,695	87,676	87,722
1981	83,223	78,685	40,953	28,148	43,910	37,520	47,371	36,213	21,471	20,064	45,692	45,879	126,192	121,674	55,793	39,560	92,605	92,550
1982	88,313	83,545	43,936	30,234	46,080	39,550	50,343	38,510	22,907	21,254	48,048	48,316	135,792	130,793	60,386	42,944	97,742	97,850
1983	93,602	88,662	46,975	32,383	48,330	41,740	53,611	41,111	24,148	22,545	50,465	51,153	146,074	140,822	65,303	46,735	103,395	103,259
1984	99,192	94,005	50,276	34,817	50,650	44,050	56,960	43,832	25,571	23,903	53,084	53,782	158,254	151,989	70,522	50,761	109,196	108,971

---

[1] ERCOT did not participate in the EEI study.

[2] From EEI. *Ten-Year Report on Load Diversity Based on 1962-1971 Load Data.*

[3] From response of Regional Electric Reliability Councils to FPC Docket R-362.

NOTE: Items underlined highlight years in which actual or projected annual peaks occur in winter.

shown in table 3-7 and are also displayed graphically in figure 3-16.

Regression analyses calculated for each of the columns of percentages show that, for the 10 years for which hour-by-hour load data are available, the trend of load diversity is generally toward smaller amounts relative to both noncoincident peaks and coincident peaks. There is a slight convergence of the two regression lines indicating that better load factors were being achieved across the nation over that period.

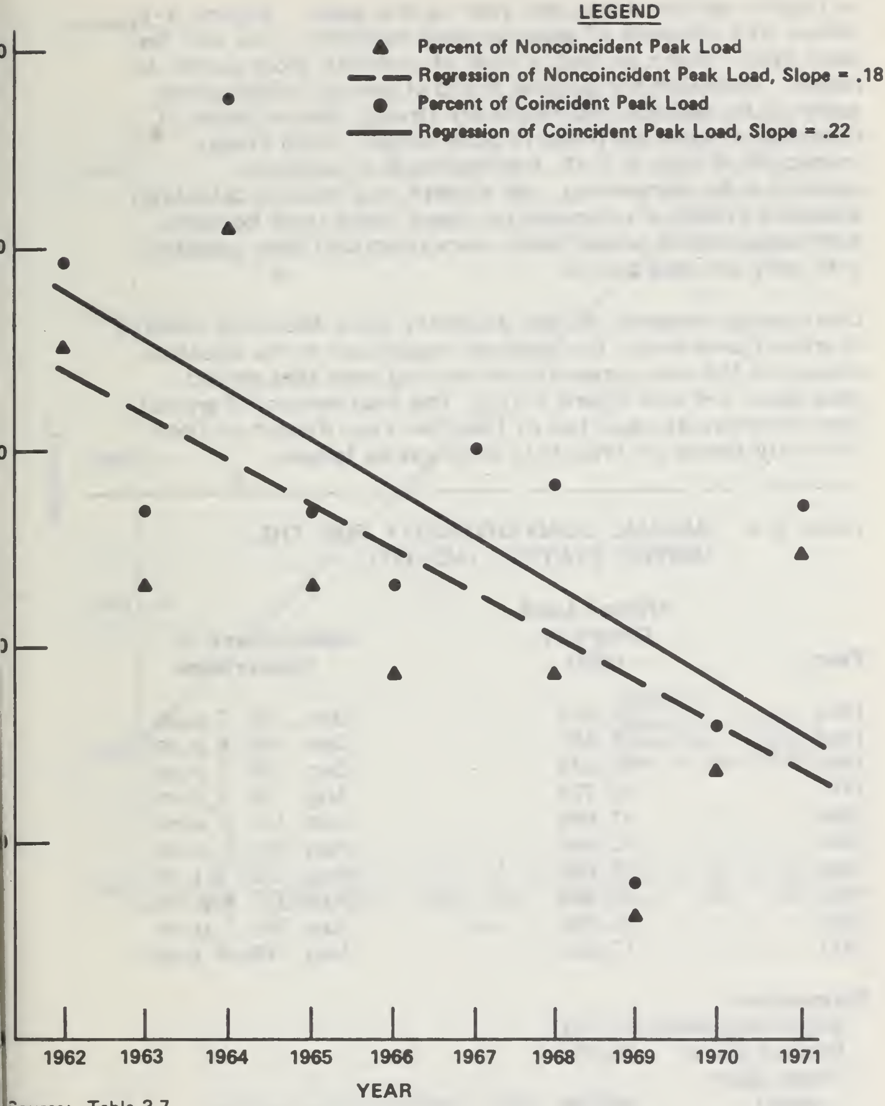
As with other measures and calculations of load diversity, no correction has been made for maintenance.

Table 3-7. ANNUAL LOAD DIVERSITY AS PERCENTAGES OF NATIONAL NONCOINCIDENT AND COINCIDENT PEAKLOADS, 1962-1971

Year	Percent of the Sum of Noncoincident Peakloads	Percent of Annual Coincident Peakload
1962	7.3	7.9
1963	6.3	6.7
1964	8.1	8.8
1965	6.3	6.7
1966	5.9	6.3
1967	6.6	7.0
1968	6.3	6.8
1969	4.7	4.8
1970	5.3	5.6
1971	6.5	6.9
Regression:		
Beginning point	7.16	7.72
Ending point	5.50	5.78
Slope (per year)	0.18	0.22

SOURCE: *Ten-Year Report on Load Diversity, Based on 1962-1971 Load Data,* Edison Electric Institute, New York. Regression by CH2M HILL.

An additional observation was made about the relationship of load diversity to peakloads. The nature of annual load diversity makes it difficult to predict with any precision its occurrence and magnitude for future years. The diversity



Source: Table 3-7

LOAD DIVERSITY AS A PERCENT OF PEAK LOADS, 1962 - 1971

Figure 3 - 16

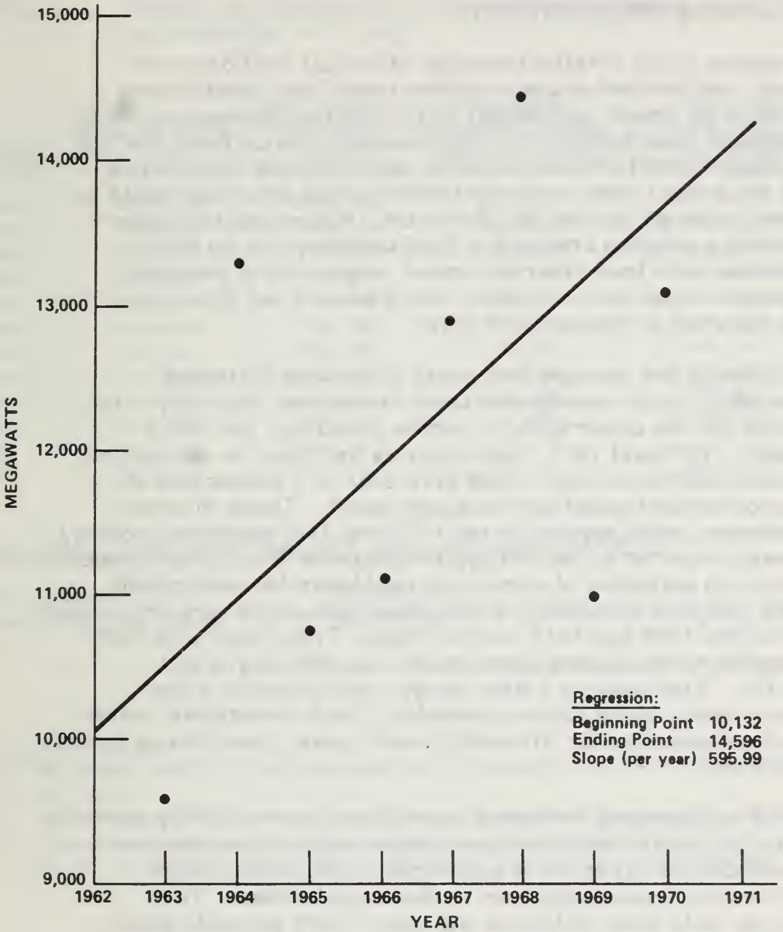
is highly volatile from one year to the next. Figure 3-15 shows this absence of year-to-year stability. As will be seen later, there is also a lack of stability from month to month. Although the general trend of annual relationships seems to be definite and relatively strong, the variation of diversity around the trend is quite large. From visual inspection of figure 3-15, the amplitude of variation appears to be dampening. No attempt was made to calculate standard errors of estimates for these trend lines because such calculations would imply more precision than possible with only ten data points.

Even though amounts of load diversity were declining relative to annual peakloads, the absolute magnitude or the absolute amount in MW was generally increasing over that period. (See table 3-8 and figure 3-17.) The total amount of annual load diversity as reported in *The Ten-Year Report on Load Diversity Based on 1962-1971 Data* was as follows:

Table 3-8. ANNUAL LOAD DIVERSITY FOR THE UNITED STATES, 1962-1971

Year	Annual Load Diversity (MW)	Date/Hours of Occurrence
1962	10,634	Dec. 12; 7 p.m.
1963	9,697	Dec. 18; 8 p.m.
1964	13,379	Dec. 18; 7 p.m.
1965	10,778	Aug. 16; 2 p.m.
1966	11,064	July 12; 3 p.m.
1967	12,900	July 24; 3 p.m.
1968	14,019	Aug. 23; 2 p.m.
1969	10,924	July 16; 4 p.m.
1970	13,046	July 29; 2 p.m.
1971	17,202	Aug. 10; 4 p.m.
Regression:		
Beginning point	10,132	
Ending point	14,596	
Slope (per year)	495.99	

SOURCE: *Ten-Year Report on Load Diversity, Based on 1962-1971 Load Data*, Edison Electrical Institute, New York. Regression by CH2M HILL.



Source: Table 3-8

ANNUAL LOAD DIVERSITY, 1962 - 1971

Figure 3 - 17

Estimating Future Diversity

Because of the volatile behavior of annual load diversity data, we decided to use a method other than determining trends by linear regression and using the regression line to estimate future diversity. Furthermore, since there are not enough historical data points to determine the true nature of the annual load diversity trend, simple analyses would be more appropriate for the short run. Future studies undertaking a detailed analysis of load behavior can be more precise with load diversity trend shapes. It is possible that the trend is curvilinear, but a base of ten data points is too small to determine if it is.

Following the straight line trend to provide estimates possibly could have understated future load diversity. To allow for the uncertainty of simple trending, the last 2 years, 1970 and 1971, were used as the basis for estimating future load diversity. Load diversity as a proportion of noncoincident peakloads was calculated. These diversity estimates were applied to the 1975 and 1976 estimated monthly peaks reported to the FPC by the Regional Reliability Councils, yielding estimates of coincident peakloads for each month. The range of coincident to noncoincident peaks was determined from the 1970 and 1971 monthly data. This range was then applied to the diversity estimates (see tables 3-9 and 3-10). The range is rather large, providing for added uncertainty about future diversity. Such uncertainty makes system planning for diversity-based power interchange tenuous at best.

This rudimentary method of estimating future monthly diversity will be greatly improved once ample hourly load data are available for all or for a statistically acceptable sample of electric power suppliers in the United States. The larger data base will allow the use of more accurate statistical methods than possible here.

If the forecast diversity and estimated range of its occurrence are considered reasonable, a minimum of 3,000 MW diversity could be expected in the country at all times. It could occasionally range upward to a maximum of about 50,000 MW. For most of the time, however, diversity could be expected to approximate the forecast. Thus, 3,000 MW would be the amount dependable enough to serve as a basis for system planning. All the remainder, because of its erratic and unpredictable nature, should be treated as diversity that may serve short-term and economy energy sales and exchanges.

One major drawback to using the 3,000 MW of diversity for system planning is that it is relatively a small amount and

Table 3-9. MONTHLY AND ANNUAL LOAD DIVERSITY AMONG NERC's ESTIMATED FOR 1975 (MW)

Month	Noncoincident Load	Estimated Coincident Load[1]	Estimated Average Monthly Load Diversity	Range of Load Diversity Estimates[2]
Jan	310,549	296,574	13,975	±10,000
Feb	302,849	289,221	13,628	±10,000
Mar	290,783	277,698	13,085	±10,000
Apr	284,428	271,629	12,799	±10,000
May	305,553	291,803	13,750	±10,000
Jun	350,693	334,912	15,781	±10,000
Jul	365,915	349,449	16,466	±10,000
Aug	368,824	352,227	16,597	±10,000
Sep	346,455	330,865	15,590	±10,000
Oct	311,557	297,537	14,020	±10,000
Nov	312,835	298,757	14,078	±10,000
Dec	327,113	312,393	14,720	±10,000

Estimated Annual Load Diversity Among NERC Regions 1975

Noncoincident Peak = 369,974 MW
Estimated Coincident Peak = 352,227 MW

Diversity = 17,747 MW or 4.8% of noncoincident peak

---

[1] Estimated as 95.5% of noncoincident peakload. Historical data from the EEI.

[2] The 1970 and 1971 data study shows a range of coincident peak to noncoincident peak of 92.0% to 98.1% for the monthly figures, with 95.5% as the average. The range thus approximates ±10,000 MW.

Table 3-10. MONTHLY AND ANNUAL LOAD DIVERSITY AMONG NERC's ESTIMATED FOR 1976 (MW)

Month	Noncoincident Load	Estimated Coincident Load[1]	Estimated Average Monthly Load Diversity	Range of Load Diversity Estimates[2]
Jan	333,870	318,846	15,024	±10,000
Feb	324,057	309,474	14,583	±10,000
Mar	310,697	296,716	13,981	±10,000
Apr	305,021	291,295	13,726	±10,000
May	326,958	312,245	14,713	±10,000
Jun	376,246	359,315	16,931	±10,000
Jul	393,210	375,516	17,694	±10,000
Aug	396,602	378,755	17,847	±10,000
Sep	372,562	355,797	16,765	±10,000
Oct	334,925	319,853	15,072	±10,000
Nov	336,296	321,163	15,133	±10,000
Dec	352,280	336,427	15,853	±10,000

Estimated Annual Load Diversity Among NERC Regions 1976

Noncoincident Peak = 397,715 MW
Estimated Coincident Peak = 378,755 MW

Diversity = 18,960 MW or 4.77% of noncoincident peaklo its occurrence may be scattered in small individual amounts throughout the country.

---

[1] Estimated as 95.5% of noncoincident peakload. Historical data from the EEI.

[2] The 1970 and 1971 data study shows a range of coincident peak to noncoincident peak of 92.0% to 98.1% for the monthly figures, with 95.5% as the average. The range thus approximates ±10,000 MW.

For estimates of future annual diversity, data were organized into winter and summer peakloads. The annual difference between these seasonal peaks is a region's seasonal diversity. Seasonal peakloads and estimated seasonal diversity are used because diversity between loads of different regions cannot be predicted by current estimation methods. The actual seasonal peakloads as computed by Utility Consulting Services are shown in the top segment of table 3-6. The bottom segment of that table presents the estimated peakloads for winter and summer for each of the regional electric reliability councils. Winter peaks are noted. Ideally, the interchange of power across seasons yields savings in generation capacity and in the reserves required for that capacity's reliability.

None of the data specifically enumerated the already captured load diversity reflected in these actual peaks for 1970 and 1971 and in the estimated peaks for years to 1984. It is implicit that expected future interchanges of power are included in these load estimates. Therefore, the difference between winter and summer peaks within a region is its expected uncaptured seasonal diversity--capacity that could be made available, after allowing for reserves and planned maintenance, to other regions having a capacity deficit. Similarly, a system could be so unfortunate as to have ample capacity but such high overall costs that it would be desirable to purchase power on an economy basis from a lower cost producer with surplus capacity and fuel.

Since cross-season diversity interchanges are advantageous for all parties, additional interchange is highly desirable. Only little can be said, however, about the usefulness of diversity occurring in the same season in different regions. Only economy energy benefits, scarce fuel resource displacement benefits, emergency power supply benefits, reserves sharing and maintenance coordinating benefits can be derived from same-season diversity. Even these benefits are uncertain and must be approached with caution. Estimates of the magnitude of these types of benefits are tenuous.

Other Data on Load Diversity Available in 1976

We have learned that the *Ten-Year Report on Load Diversity, Based on 1962-1971 Load Data* is to be updated. Data for the years 1972, 1973, and 1974 are now being collected (September 1975).[23] Computer processing is scheduled for late 1975 and the report is scheduled for publication in late spring 1976. The additional data will reveal more about the trend of load diversity in absolute amounts and relative to peakloads. Perhaps the data will also show the beginning influence of the changes in fuel availability, financing, and demand that occurred from mid-1974 to the end of that year and beyond. They will also indicate whether the added interties allowed the capture of additional load diversity.

Availability of this more recent hour-by-hour load data will make it possible to determine the current trend of load diversity. It will also allow a much more detailed look at regional relationships in load diversity. Data on the occurrence of peakloads will show if the trend toward summer peaks has continued or if it has abated under pressure of changes in relative prices of alternative energy sources and of changes in the economy of the nation. The effects of these latter influences would be more apparent if 1975 data were available for inclusion in this study.

Load Growth

The demand for electricity has historically grown at an annual rate of about 8 percent. For decades utility industry planners have accepted that due to demand growth capacity would have to be doubled every 10 years.[24] Realization that the world supply of petroleum is limited, a realization brought on especially forcefully by the concerted action of the oil-producing countries in 1974, caused the U.S. to pay considerable attention to the energy situation. Another result of the 1974 constrained oil supply and related economic ramifications was an economic slowdown and a recession of greater depth and length than any since the Great Depression of the 1930's. The demand for electric energy has not grown during 1974 and 1975, partly as a result of this slowdown.[25]

Attention to the energy situation brought on many programs for conserving oil and other forms of energy. These conservation programs further influenced the growth rate in demand for electricity for the short years. This influence may be felt for some years in the future.[26,27] However, the electric power industry is looking forward to being able to serve the demand of the future and has forecast its capacity needs for 1975-1984. The Federal Power Commission released a report dated 30 June 1975[28] that revealed the plans for plant expansion made by individual utilities. These plans are reported annually to the regional electric reliability council of which the reporting utility is a member. The regional councils subsequently compiled the individual utility data and submitted composite reports to the FPC and the National Electric Reliability Council on 1 April each year. From the 1975 reports, the FPC projected for the nation as a whole an annual rate of growth in peak demand for the next 10 years of 6.84 percent. Each regional council projects slightly different rates of growth of peak demand as shown in table 3-11.[29]

We made a conscientious effort in this project to locate load growth projections for the reliability council regions made by any forecasting group that could not be considered to be a part of or under the influence of the electric utility industry. Officials of the Defense Department, the Federal Energy Administration, the National Science Foundation, the National Academy of Sciences, and the FPC were asked for assistance in obtaining such regional forecasts of load growth. None of the persons queried offered assistance in obtaining useful regional forecasts. The search was abandoned when we realized that agencies were referring the researchers to agencies that had been previously polled. It was concluded that all leads had been exhausted.

Mr. Frank Zarb, Administrator of the FEA, released projections for electricity demand growth based on expected impacts of that agency's load management programs and its "Utilities Conservation Action Now" program. These projections show expected growth rates of peak demand ranging from 3-1/2 to 4-1/2 percent annually until 1985. The corresponding projected growth rates for energy sales ranged from 4-1/2 to 5-1/2 percent annually.

Projecting peak demand to grow at a lower rate than energy sales means that there is an expectation that various programs instituted by the FEA, plus effects of the current economic recession, the uncertain availability of fuels used to generate electricity, and changing relative prices of all energy alternatives will have a substantial effect on the demand for electricity at peak, such that load factors (average loads in MW ÷ peakloads in MW), will be improved from 62 to 69 percent in the 10 years until 1985.[30]

The objective of a load management program directed at improving load factors is to shift some energy uses from onpeak to offpeak times. This can be done on both a daily and seasonal basis. Figure 3-18 illustrates the intended effect of peakload management.

If load factors are improved uniformly throughout the regions of the U.S. through reducing the growth rate of peak demand with respect to that of average demand, diversity that has not been captured will be reduced. It is possible that improved load factors on each electric power system will impinge on the availability of the diversity that is now captured.

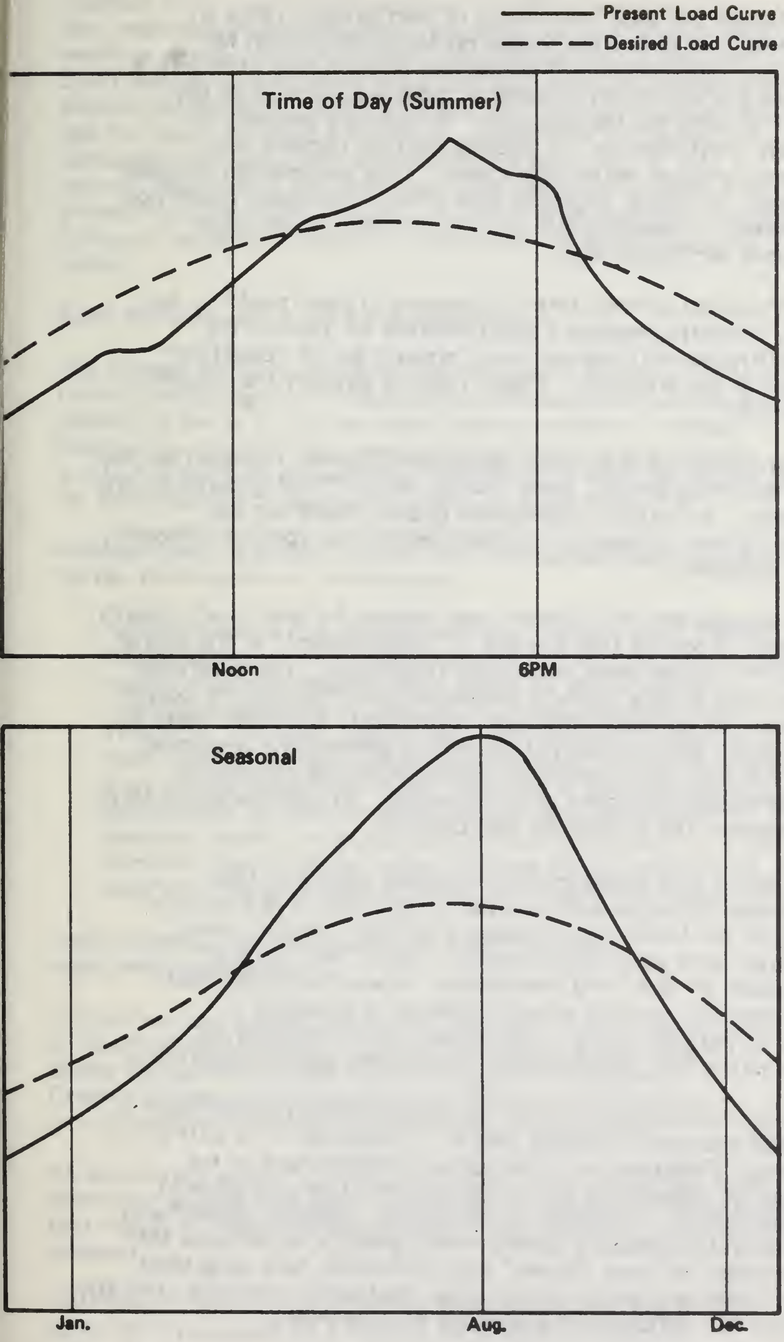
Table 3-11. PROJECTED ANNUAL PERCENTAGE INCREASE IN DEMAND ONPEAK

	Council									
Year	ECAR[1]	ERCOT[1]	MAAC[1]	MAIN[1]	MARCA[1]	NPCC[1]	SERC[1]	SPP[1]	WSCC[2]	The Nation[1]
1975	--	--	--	--	--	--	--	--	--	--
1976	8.33	9.02	5.45	6.47	7.28	5.34	8.70	8.04	6.32	7.36
1977	7.40	9.26	5.85	8.37	9.18	5.55	9.07	9.29	6.81	7.82
1978	6.84	8.46	5.81	6.78	6.87	5.00	7.96	7.92	6.77	7.04
1979	6.41	8.18	5.30	6.54	6.35	5.13	7.85	8.40	5.58	6.71
1980	6.32	7.91	5.21	6.53	6.17	4.89	7.63	8.30	5.67	6.61
1981	6.27	7.45	5.10	6.32	6.23	5.13	7.59	7.38	5.62	6.47
1982	6.12	7.28	4.94	6.27	6.69	5.16	7.61	8.23	5.55	6.52
1983	5.99	6.92	4.88	6.49	5.42	5.03	7.57	8.14	5.78	6.46
1984	5.97	7.03	4.80	6.25	5.89	5.19	8.34	7.99	5.61	6.62
Annual Average	6.63	7.94	5.26	6.67	6.68	5.16	8.03	8.19	5.97	6.84

---

[1] Summer peak in 1975.
[2] Winter peak in 1975.

SOURCE: FPC. Special provision of summary computer-produced tables, 8/5/75.



EXAMPLE OF THE OBJECTIVE
OF PEAKLOAD MANAGEMENT

Figure 3 - 18

To estimate the possible effects of load growth rates on diversity, we chose the following levels of growth for analysis. The industry's historical growth rate of nearly 8 percent per annum in demand at peak was chosen as the "high" growth for the analysis. A rate of 8 percent is applied to all regions. It implies that all regions are assumed to grow at uniform rates. This assumption is made because, as noted, regional load growth forecasts could not be located. It would have been prohibitive to do such forecasts for this project.

The projected growth rates of demand at peak made by the utility industry members and compiled for each of the reliability council regions were chosen as the "baseline" growth of the analysis. These rates of growth are shown in table 3-11.

The projected growth rates of demand at peak released by the FEA, as noted above, were chosen as the "low" growth for the analysis. As with the historical growth rates for the nation, these national projections were also applied uniformly to all regions.

Even though the FEA release was chosen for the "low" growth analysis, because that agency is "independent" of the power industry, it was done with some reluctance. Considerable experience of this study's researchers in the electric power industry in the East, Midwest, Southeast, and West leads to an *a priori* conclusion that the FEA's projections are somewhat too low, even under an assumption that its energy conservation programs are successful. The following excerpt summarizes the reason for our caution.

> "While it is apparent to the casual observer that loads increase with population growth, it is also true that the loads will increase over the long run even with zero population growth. On a 'zero growth' study by the Ford Foundation, it was estimated that electrical growth would increase at a rate of 2.5 percent a year. Moreover, the study did not assume any conversions from oil and gas to electricity."[31]

Load growth forecasting has been undergoing rather substantial changes in recent years.[32] Even so, it is still in its infancy. Peakloads are the current determinant of the amount of capacity of capability that must be available to supply power. Demand is, of course, weather related and it is as yet impossible to accurately predict in advance the occurrence of "heat storms" and blizzards, how long they will remain and influence an area, and what wind and humidity factors will influence the demand for electricity.

Another influence on demand that is difficult to predict is that resulting from changes in the relative availability and relative prices of fuels that are substitutes for electricity. Even though recent years have brought about increased use of electricity for air-conditioning and the expansion of use of gas for space heating,[33] changes in relative prices may stimulate conversions to electricity for heating. If this occurs, the rate of growth in demand could be greatly accelerated from the 1974-75 level. It could approach the industry forecast, or even surpass it, and return to the historical trend.

Some Very Recent Load Growth Estimates

The Edison Electric Institute has released a report, *Economic Growth in the Future*, based on an 18-month study of economic growth of the U.S. In the report extremes were avoided. Electricity consumption was estimated to grow at a rate of 5.3 to 5.8 percent per annum, "about twice the rate projected for total energy consumption (*EWk*, 2 June 1975)."[34]

Another view of future growth rates was presented recently by the Westinghouse corporation.

> "Westinghouse has warned electric utilities that if they let the past summer's low peakload growth trigger another round of plant cutbacks they could be in for severe capacity shortages during much of the decade of the 1980's. . . If there should be a new round of plant cutbacks and deferrals based on new utility projections of 5.5% annual growth through 1980 and if the Westinghouse projections of some 9% are realized, the generation margins would dip below the 10% level by 1980. . . . A General Electric large steam turbine official expressed no sharp disagreement with the Westinghouse thesis. . ."[35]

Load Growth, Load Management, Load Factors, and Load Diversity

System planners need to be able to estimate how load growth will influence diversity. Load diversity is an important factor in determining the need for capital investment. Growth in loads will alter diversity patterns unless the growth occurs in an unusually constrained manner.

As mentioned earlier, when load factors are improved, load diversity will be reduced. Conversely, if loads grow in patterns that result in reduced load factors, load diversity will be increased.

Diversity is the sum of noncoincident peakloads minus the coincident peakload on a system or within a region or within the nation. Load growth that raises the magnitude of the coincidental peakloads relative to the sum of the noncoincident peakloads will reduce the diversity on which broad system planning relies. By similar reasoning, any load growth that raises the offpeak consumption of electricity relative to the peakload reduces load diversity of the type on which economy interchange of power depends.

As shown in tables 3-1 and 3-2, diversity for 1970 and 1971 was respectively 5.5 and 5.8 percent of the annual national coincident peaks. If it is accepted that diversity may be counted on to approximate this percentage and if a load growth rate of 8 percent is applied, a diversity of one absolute magnitude will result; if the industry load growth projections are applied, diversity of a smaller absolute magnitude will result; if the FEA projection of growth of 4 percent is applied, diversity of a small absolute magnitude will result.

See tables 3-12 and 3-13 for estimates of future load diversity. These estimates were developed by applying the three selected load growth rates and the assumed load diversity to 1975 annual peak estimates released by the regional electric reliability councils.

Another estimation method was used to develop table 3-14. The winter and summer peak estimates for 1975 were projected for 1980 and 1984 using the three selected load-growth rates. These estimates carry forward the 1975 seasonal diversity and reflect only the load growth. No changes in relative load diversity are assumed.

These two methods of estimating indicate that load growth is one important determinant of load diversity.

The recently released EEI study of economic growth does not elaborate on the influences that cause the specific rate of load growth given in the report.[36] However, this new, lower forecast, is such a departure from the historical trend and from the industry's planning projections that it seems likely that some distinctive influence was included in the analysis. When it is considered that the EEI projection closely approximates those released by FEA in June, one must reason that the FEA load management programs[37] and economic conditions are expected by EEI to influence the demand for electric energy and, thereby, load diversity.

One problem with this type of load diversity analysis is that numerical values for changes in load factors cannot be included. Efforts are being made by the FEA to alter load shapes with its load management program; by the FPC with its general encouragement for cooperation among utilities for

Table 3-12. ANNUAL PEAKLOAD ESTIMATES AND ESTIMATES OF DIVERSITY BY RELIABILITY COUNCIL, 1980 AND 1984

	ECAR		ERCOT		MAAC		MAIN		MARCA		NPCC		SERC		SPP		WSCC	
	Peak-load	Diver-sity	Peak-load	Diver-sity	Peak-load	Diver-sity	Peak-load	Diver-sity	Peak-load	Diver-sity	Peak-load	Diver-sity	Peak-load	Diver-sity	Peak-load	Diver-sity	Peak-load	Diver-sity
Projections - 1980																		
4% per FEA	67,746	3,929	30,748	1,783	38,848	2,253	38,768	2,249	17,398	1,009	41,075	2,382	96,051	5,571	42,260	2,451	78,866	4,574
Industry	78,313	4,542	38,114	2,211	41,780	2,423	44,557	2,584	20,212	1,172	43,462	2,521	117,288	6,803	51,960	3,014	87,676	5,085
Historical (8%)	81,815	4,745	37,134	2,154	46,916	2,721	46,817	2,715	21,011	1,219	49,606	2,877	115,999	6,728	51,037	2,960	95,245	5,524
Projections - 1984																		
4% per FEA	79,253	4,597	35,971	2,086	45,446	2,636	45,353	2,630	20,354	1,181	48,052	2,787	112,367	6,517	49,437	2,867	92,263	5,351
Industry	99,192	5,753	50,276	2,916	50,650	2,938	56,960	3,304	25,571	1,483	53,084	3,079	158,254	9,179	70,522	4,090	109,196	6,333
Historical (8%)	111,309	6,456	50,521	2,930	63,828	3,702	63,694	2,694	28,586	1,658	67,488	3,914	157,815	9,153	69,435	4,027	129,579	7,516

Table 3-13. LOW, MEDIUM, AND HIGH PROJECTIONS OF ANNUAL PEAKLOADS AND DIVERSITY, 1980 AND 1984

	Estimated Peakloads	Estimates of Diversity[1]
Projections - 1980		
4% per FEA	451,760	26,202
Industry	523,362	30,355
Historical (8%)	545,580	31,644
Projections - 1984		
4% per FEA	528,496	30,653
Industry	673,705	39,075
Historical (8%)	742,255	43,051

---

[1] Assuming same percentage as 1971 - 5.8%.

Table 3-14. COMPARISON OF PEAKLOAD GROWTH SCENARIOS'S BY RELIABILITY COUNCIL, 1980 AND 1984

	ECAR		ERCOT		MAAC		MAIN		MARCA		NPCC		SERC		SPP		WSCC	
	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Base - 1975	55,682	52,999	25,273	17,694	31,930	26,710	31,863	24,859	14,300	13,103	33,761	33,276	78,947	77,264	34,735	24,398	64,822	64,940
Projections - 1980																		
4% per FEA	67,746	64,481	30,748	21,527	38,848	32,497	38,768	30,243	17,398	15,942	41,075	40,485	96,051	94,004	42,260	29,685	78,866	79,011
Industry	78,313	74,109	38,114	26,103	41,780	35,570	44,557	34,077	20,212	18,876	43,462	43,516	117,228	112,818	51,960	36,695	87,676	87,722
Historical (8%)	81,815	77,873	37,134	25,998	46,916	39,246	46,817	36,526	21,011	19,253	49,606	48,893	115,999	113,526	51,037	35,849	95,245	95,418
Projections - 1984																		
4% per FEA	79,253	75,434	35,971	25,184	45,446	38,017	45,353	35,380	20,354	18,650	48,052	47,362	112,367	109,972	49,437	34,727	92,263	92,431
Industry	99,192	94,005	50,276	34,817	50,650	44,050	56,960	43,832	25,571	23,903	53,084	53,782	158,254	151,989	70,522	50,761	109,196	108,971
Historical (8%)	111,309	105,945	50,521	35,370	63,828	53,393	63,694	49,693	28,586	26,193	67,488	66,519	157,815	154,451	69,435	48,772	129,579	129,815

interconnection, reserve sharing, and economy interchange of energy; and by the state commissions with rate reforms designed to reduce peakloads and encourage offpeak usage. As a result, it is difficult to predict future load factors with much certainty. With no estimates of load factors, no firm estimates of future load diversity can be made.

However, the available evidence leads us to believe that the nation's load factor will be improved. One result of this will be a smaller total amount of load diversity, unpredictable at this point, available to serve as a benefit from interregional EHV and UHV transmission systems.

SUMMARY AND FINDINGS

1. Load diversity is measurable but rather erratic, therefore elusive to capture.

2. Short-term load diversity does not provide a basis for system planning and realization of capacity savings.

3. Short-term load diversity is best utilized on an interutility coordinated, operational basis.

4. No currently employed method provides a measure of short-term load diversity or the amount already utilized.

5. Seasonal load diversity is also erratic, but more predictable than short-term load diversity.

6. Electric supply systems are now, and have been employing for some time, seasonal diversity in system planning and operations. The result is a saving of installed generating capacity.

7. Seasonal diversity is greatly influenced by weather and economic factors, such as prevalence of air-conditioning and the availability and prices of alternate energy sources.

8. Time-zone load diversity has long been thought to be large enough to offer significant savings in capacity by displacement transfer of power from offpeak to onpeak time zones. However, this notion is not supported by available data.

9. The load patterns of the United States have changed radically since the *National Power Survey of 1964*. There has been widespread growth in intercompany interconnections and a vast growth in the use of electricity for air-conditioning. These two changes have reduced diversity available for interregional interchange.

10. Work on load diversity has been conducted independently by the FPC and by the Edison Electric Institute.

11. EEI has done the most comprehensive study of load diversity. This study was carefully analyzed. Its objectivity and usefulness were verified for this report.

12. The EEI *Ten-Year Report on Load Diversity, Based on 1962-71 Load Data* showed a change from national winter peak to national summer peak in the early 1960's. The magnitude of the summer peak has since grown steadily.

13. Also shown was a general trend toward an increase in total MW of load diversity but a decrease in load diversity as a percentage of total loads. Furthermore, there is evidence that load factors have steadily been improving.

14. An additional finding of the EEI study was that time-zone diversity is decreasing both absolutely and relatively as peaks broaden.

15. More and more areas in the northern tiers of states find that they have shifted from a winter to a summer peak, reducing possibilities for a winter/summer interchange between regions with peaks occurring in different seasons.

16. Load diversity of all types is difficult to predict with satisfactory accuracy.

17. Load diversity among regions is scattered broadly in relatively small amounts in individual locations.

18. FEA is encouraging actions by utilities and regulatory agencies that are aimed at improving load factors and reducing peakloads. These programs, if successful, will reduce load diversity substantially.

19. Further actions by various agencies to increase the relative price of natural gas and discourage oil heating will encourage shifts to electric heat, thus increasing the possibility of winter peaks in gas-poor regions and increasing seasonal load diversity.

20. The EEI is planning to revise the *Ten-Year Report on Load Diversity, Based on 1962-71 Load Data*, and results based on load data through 1974 probably will be released early in 1976.

21. There is much controversy over the estimation of future electric loads. Load-growth estimates range from 9 percent per annum down to 3.5 percent. The industry itself, with its responsibility to serve, seems best capable of predicting demand in the future. That load growth estimate is 6.84 percent per annum through 1984. A recent EEI report contains electric load growth estimates of 5.5 percent through 1984.

22. Load growth as well as changes in load factor affects the amount and occurrence of load diversity.

23. This study estimates that, before allowing for planned maintenance, there will be about 30,000 MW to 43,000 MW of load diversity in 1984, depending on load growth assumptions. These amounts appear large, but they represent only about 6 percent and 10 percent respectively of the peakload forecasts derived from assumed load growths of 4 percent and 8 percent.

24. It must be emphasized that these estimates have not been adjusted for planned maintenance which, for practical reasons, is scheduled to be conducted during offpeak periods.

25. When the planned maintenance scheduled for periods when spare generating capacity made available by load diversity is accounted for, the amount of load diversity usable to reduce generating capacity is reduced to negligible amounts.

■ FOOTNOTES TO CHAPTER 3

1 Edison Electric Institute. 1974. *Ten-year report on load diversity, based on 1962-71 load data.* New York, N.Y. A report of the subcommittee on load diversity.

2 Federal Power Commission. 1964. *National power survey.* Washington, D.C. U.S. Government Printing Office. p. 175. Also, McDaniel, G. H., and Gabrielle, A. F. July 1965. Load diversity--its role in power system utilization. *IEEE Journal.* pp. 626-635.

3 Federal Power Commission. 30 June 1975. Federal Power Commission issues staff summary of electric utility expansion plans for 1975-1984. *Federal Power Commission news release No. 21520.* p. 4.

4 Federal Power Commission. October 1972. *Study of proposed interconnection between Electric Reliability Council of Texas and Southwest Power Pool.* Bureau of

Power staff report. Fort Worth, Texas. FPC Fort Worth Regional Office.

5 McDaniel, G. H. and Gabrielle, A. F. July 1965. Load diversity--its role in power system utilization. *IEEE Journal*. p. 626.

6 Ibid., p. 626.

7 Federal Power Commission. 1964. *The national power survey*. Washington, D.C. Chapter 13, p. 179.

8 Ibid., p. 179.

9 Ibid., p. 179.

10 Edison Electric Institute. 1974. op cit.

11 Edison Electric Institute. May 1969. *Instructions for data preparation for the Edison Electric Institute load diversity study*. New York, N.Y.

12 There were data asked for that depended on the judgment of the data supplier. None of these data items could influence the determination of peak or the hours of occurrence.

13 Western Systems Coordinating Council (WSCC), Mid-Continent Area Power Planners (MAPP), Mid-America Interpool Network (MAIN), and East Central Area Reliability Agreement (ECAR). July 1969. *An appraisal of transmission study 190.*

14 Mid-Continent Area Power Pool (MAPP), Missouri Basin Systems Group (MBSC), and Southwest Power Pool (SPP). December 1973. *Report of the western United States: central United States study of transmission interconnection.*

15 Edison Electric Institute. *EEI load diversity study - time zone load study, 1970 and 1971.* New York, N.Y. Subcommittee on Load Diversity.

16 Edison Electric Institute. 1974. *Ten-year report on load diversity, based on 1962-71 load data.* New York, N.Y. A report of the Subcommittee on Load Diversity. p. 37.

17 Ibid.

18 *Electrical World*. 15 May 1975. pp. 62 and 63.

19 Federal Energy Administration. 1975. *Utilities conservation action now*. Washington, D.C. Materials prepared on the UCAN program.

20 *Public Utilities Reports*. 8 August 1974. Re Madison Gas and Electric Company. Washington, D.C. 5 PUR 4th, pp. 28-61.

21 James, Richard D. 17 September 1975. Pacific Gas and Electric gets a rate increase of $213.4 million. *Wall Street Journal*. vol. XCIII, No. 55. p.2.

22 APPA. 15 August 1975. Electric heat outpaced gas in 1974 new houses. *Public Power Weekly Newsletter*. Washington, D.C.

23 Telephone conversations with Mr. Charles W. King of Utilities Consulting Services, Inc., 20 August 1975,

and with Mr. Jerome L. Weiser of the Edison Electric Institute, 18 July 1975.

24 The Bureau of National Affairs, Inc. 17 July 1975. Electric power: head of research group sees need for double production every 10 years. *Energy User's Report*. p. A17.

25 *Electric Light and Power*. 21 July 1975. The top 100 electric utilities - 1974 - a year of zero growth. pp. 7-11.

26 Public Utilities Reports, Inc. 31 July 1975. FPC says electric growth will slow down. *Public Utilities Fortnightly*. Washington, D.C. p. 13.

27 Edison Electric Institute. 1975. *Economic growth in the future*. New York, N.Y.

28 Federal Power Commission. 30 June 1975. op cit.

29 The Federal Power Commission provided composite regional calculations based on the Regional Electric Reliability Council reports in response to FPC Order 383-3.

30 *Electrical Week*. 16 June 1965. p. 2.

31 Thompson, Wayne. 24 August 1975. Northwest power shortage will equal four Bonnevilles. *The Sunday Oregonian*. Portland, Oregon. Section F, p. 1.

32 Asbury, C. E. July/August 1975. Weather load model for electric demand and energy forecasting. *IEEE Transactions on Power Apparatus and Systems*. vol. PAS-94, No. 4. Paper T73, 453-8.

33 *Electrical World*. 15 May 1975. Slump in winter peak growth persists.

34 *Electrical Week*. 15 September 1975. p. 4.

35 *Electrical Week*. 22 September 1975. p. 6.

36 Edison Electric Institute. 1975. *Economic growth in the future*. op cit.

37 Federal Energy Administration. 1975. *Utilities conservation action now*. op cit.

Chapter 4
RESERVES

THE NEED

When bulk power supply systems interconnect, a number of possible benefits can accrue to them. These benefits are related to the economies of scale that exist in the electric power industry.[1]

The primary benefits of interconnection between systems include a reduction in the amount of generating reserves that must be maintained and improvement in system reliability. Diversities in system generator outages and system load conditions allow interconnected systems to operate with less reserves than would be required for isolated operation. For example, if each of two isolated systems generated its power with a 1,000-MW unit, each would have to have 1,000 MW of forced-outage reserve to prevent service interruption should the main unit fail.[2] If the two systems were to interconnect so that transmission capacity presented no limitations, the systems could share reserves so that each system would require only 500 MW of forced-outage reserve with the other 500 MW available from the other system. This example is illustrative only, since, in both cases, the rare occurrence of a simultaneous two-machine outage must be considered.

These benefits can be used in several ways while maintaining the same degree of, or improved, overall reliability. The level of both installed and operating reserves may be reduced, or the systems may install larger units which might preclude the lowering of reserves.[3] It has been pointed out that with the advent of nuclear units the benefits of full coordination have many times been realized by adopting very large generating units, even when this has actually increased reserve requirements.[4]

The decisions interconnected systems make on how to best utilize the economies resulting from interconnection will depend on many variables such as: (1) system sizes, (2) generation mix,[5] (3) present levels of reliability and reserves, (4) fuel availability, (5) interconnection limitations, (6) geographical situations, (7) individual system load characteristics, (8) type of agreement between the systems, (9) level of trust between the systems, and (10) the regulatory climate in which the systems operate.

In order to assess the impact of high-capacity interconnections on reserve levels, it is useful to analyze the reasons for reserves. An electric generating system must have installed capacity that exceeds the expected peakload for many reasons. This excess capacity, called reserves, must be provided to ensure against planned and emergency generator outages or other inadequacies.

---

[1] See footnote references, end of chapter.

The system's reserve requirements depend upon a number of factors including the size, number, and types of generating units, fuel availability and type, and system load characteristics, including the duration of demand peaks (which can influence the time available for maintenance). Generator unit forced-outage rates (affected by type of equipment, fuel used, and weather), errors in predicting future demand, the system size, degree of interconnection, and configuration of transmission lines also play a part.

System load will never be completely predictable. The actual load, both in terms of capacity needed to meet the peak demand and energy needed to meet requirements, is dependent on economic conditions, weather, degree of saturation with electricity-using devices, and the pricing and availablility of fuels which can be substituted for electricity.

Historically, electric usage has grown annually approximately 7.7 percent for peak demand and 7.0 percent for energy requirements. Because of the recent recession and emphasis on energy conservation, the peak and energy growth rates each were about 1.0 percent from the end of 1973 through 1974. This could not have been predicted even as recently as 1971 with the degree of certainty desired for utility planning.

Weather uncertainty must be taken into account because a portion of most systems' loads is weather sensitive. For example, Bonneville Power Administration (BPA) estimates that for 1974-75 the Northwest Power Pool (NWPP) had a temperature sensitivity of 177.6 megawatts per degree Fahrenheit. This temperature-sensitive increment represented about 1 percent of the actual NWPP peakload.[6]

A system's load characteristics also depend on the types of loads it serves. The extent to which the service area is saturated by electric water heating, space heating, and air-conditioning has a great effect on load characteristics. At one time most areas of the United States were winter peaking but, with increased use of air-conditioning, many areas have become summer peaking.

There are now indications that high prices and unavailability will cause consumers to shift from oil and natural gas to electricity for such uses as space heating. If this occurs, system load characteristics might be altered considerably.[7]

Compounding the problem of load uncertainty is the unpredictability of generation unit availability.[8] Generators require periodic checking and maintenance, and, as today's units grow more complex and sophisticated, the need for adequate maintenance has increased.[9] Coupled with the need to provide "reserve" capacity to allow for maintenance is the need to have capacity for forced (unscheduled) outages. Forced outages may be either complete or partial. Complete forced plant outages result almost entirely from equipment failures and malfunctions.[10] Partial forced outages result primarily from the failure and malfunction of one of a number of components operating in parallel. Some causes of forced outages not related to equipment failure include poor quality coal, boiler fireside cleaning, and cooling water temperature limitations.

A utility also must carry reserves because of its inability to anticipate the future perfectly. Many constraints placed on a utility are beyond its control. Environmental considerations have delayed the scheduled full commercial operation of many plants. Technology has not always progressed as rapidly as anticipated. Fuel availability may cause problems; if a utility has oil-fired generation and oil is not available, it must have alternative capacity or obtain assistance from a system which has excess capacity.

Utilities, historically committed to meet demand and to provide service when requested, have considered it prudent to err on the side of having excess capacity. Long-run schedules for generation installation usually can be delayed, but it is impossible now to bring baseload capacity on-line with much less than 8 to 10 years' lead time. If, in order to meet its load, a utility installs peaking units which have shorter lead times but cost much more to operate than baseload units, its cost of generating energy will increase greatly.[11]

DETERMINING RESERVE REQUIREMENTS

At present, most utilities use as one of their planning tools probability-based methods of analysis to determine system reliability or the probability that they will not be able to meet their load with the resources available to them.[12] Of the methods available for analyzing system reliability, the loss-of-load probability (LOLP) method seems to be the most popular in the industry.[13] In this method the probability of loss of capacity due to simultaneous outages is superimposed on the probability of the coincidence of the loss of capacity with heavy load demands. The results show the expected frequency of loss of load for given capacity and load conditions. As presently applied, the results do not show the magnitude of excess or deficiency. The magnitude of a deficiency can be determined only by making repeated trial calculations, each time adding an increment of capacity to the system.[14] The LOLP approach is relatively simple to appreciate and can be applied easily to the analysis of equipment configurations to determine their effect on overall system reliability.[15]

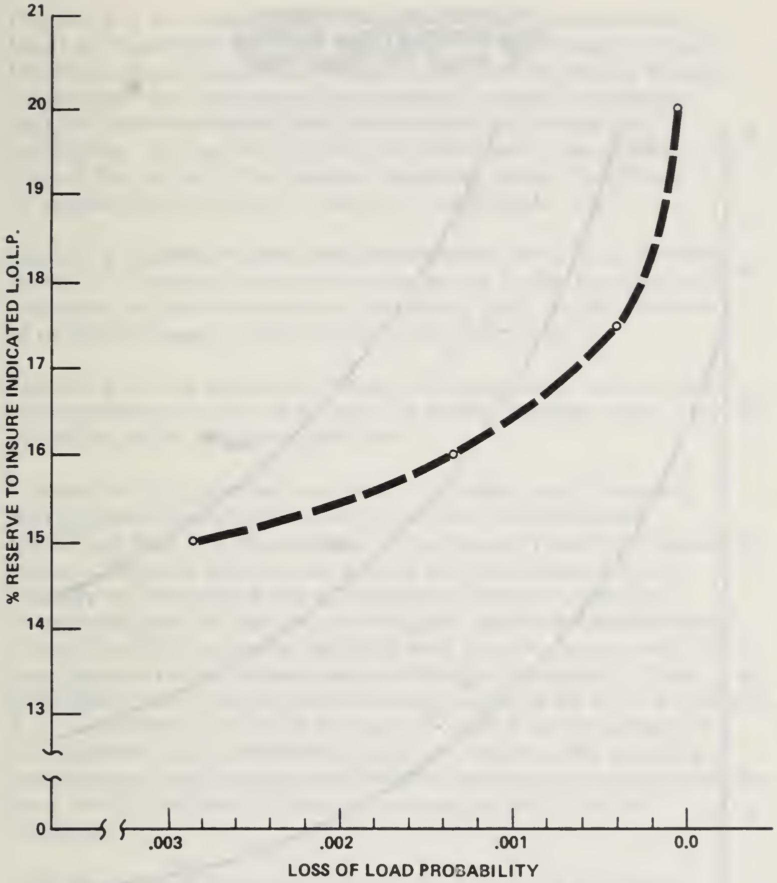
Presently, most utilities use as a planning basis a LOLP index of "1 day in 10 years." This means that there is the possibility that available capacity will not be able to meet expected load for a duration of 1 day in 10 years or 0.04 percent of the time.[16] This measure of reliability has its value based on the judgment of planning engineers.[17] The debate on the appropriateness of this index will probably intensify as utilities must raise rates and find it more difficult to borrow the large amounts of capital they require.[18] One electric utility executive feels that utilities could lower their generating reserves by 8 percent and still provide service in consonance with distribution system reliability.[19]

FACTORS AFFECTING RESERVE LEVELS

Many papers have been written, utilizing various methods, analyzing the impact of various parameters on a system's reserve requirements. It must be noted that the results in each paper depend greatly on the assumptions used. However, in reviewing the quantity of work done, we find that the results are relatively consistent regardless of the assumptions used.[20]

Work done by Mabuce, Wilks, and Boxerman[21] (see figure 4-1) indicates that, as a system attempts to achieve perfect reliability, the level of reserves required increases greatly. As would be expected, when a system attempts to protect itself against contingencies that are less and less likely, the price of that protection increases drastically. The graph indicates that an LOLP probability of 1 day in 10 years would require a reserve level of 17.5 percent. The shape of the curve indicates a small increase in system reliability would greatly increase reserve requirements. Any decrease of reserves would cause a decrease in system reliability.

The relationship of required reserves to pool size has been analyzed in several papers.[22] In each paper it was found that, as the number of units of a given size on a system increased, the required reserve level decreased (see figure 4-2).



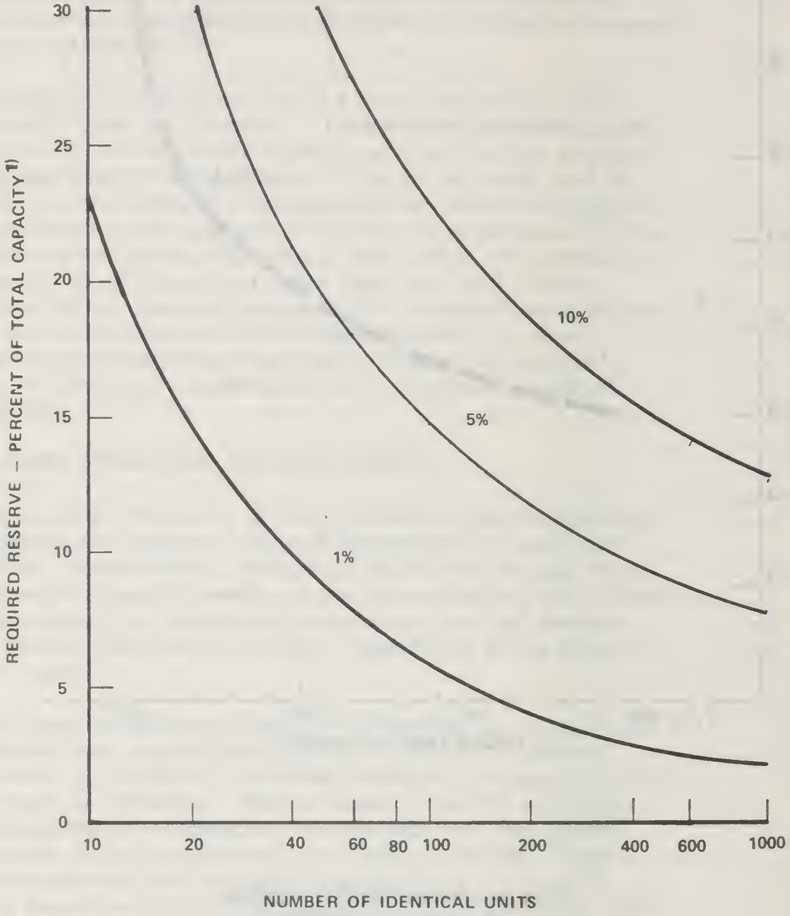
RESERVE REQUIREMENT VERSUS
L.OL.P. LEVEL DESIRED

Source:

Mabuce, Estel M., Wikes, Richard L. and Boxerman, Stuart B., Generation Reserve Requirements, Sensitivity to Variations in System Parameters. IEEE Transactions on P.A. & S.

Figure 4 - 1

FORCED OUTAGE RESERVE
FOR HYPOTHETICAL SYSTEMS
1%, 5% and 10% Outage Rates[1]



[1] Average Duration of Five Days, Average Frequencies Are Once in 500, 100, or 50 Days, Giving Forced Outage Rates of 1%, 5% and 10%.

[2] For Loss of Margin Less Than Once in 5 Years on the Average.

The portion of capacity required for reserve generally decreases as the system grows. This is illustrated above for groups composed of ten or more identical units.

Source:

Federal Power Commission, National Power Survey,
Washington D.C. Government Printing Office, October 1964

Figure

Figure 4-3 also shows that as system size increases the level of required reserves decreases. This result is due to the diversity of generator outages and the lessening impact the outage of a unit has on the overall system, assuming that the relative size of the largest unit on the system decreases. If, as the system size increases, the relative size of the units in the system stays the same, the effect of system size on reserve levels is negligible.

Figure 4-2 contains the same information only in a different format. It relates system reserve levels to the number of identical units on the system, showing that, as the number of units increases, the reserve level decreases.

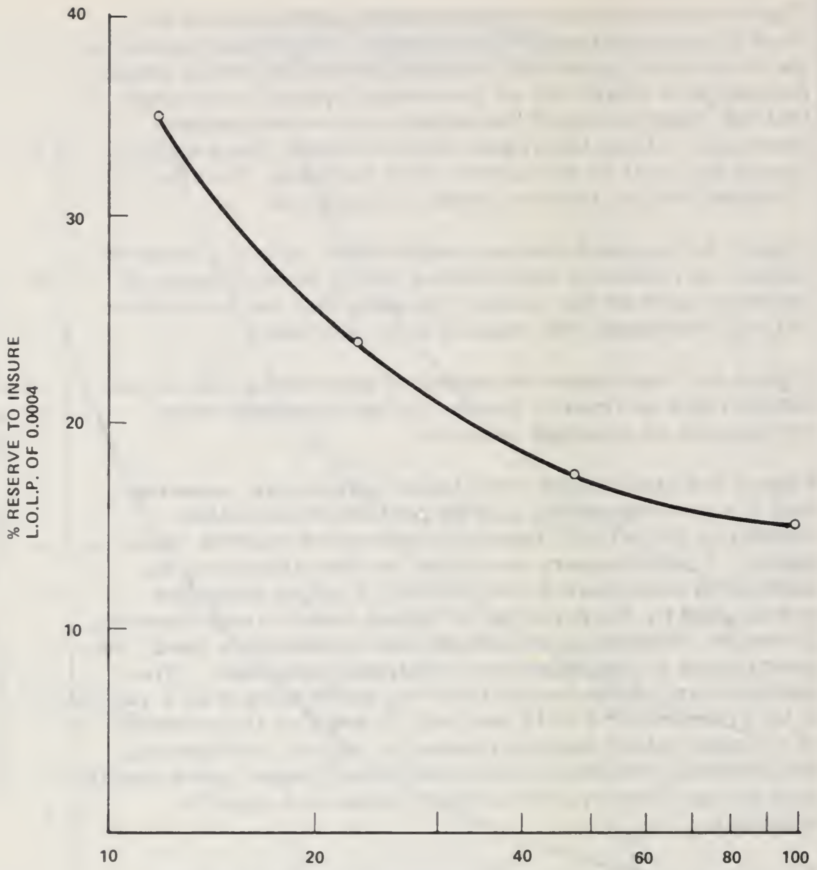
Figure 4-2 also shows the impact of generating unit forced-outage rates on reserve levels: as forced-outage rates increase so do required reserves.

Figure 4-4 also relates unit size to system size, showing that if a unit represents a large portion of the system capability there is the penalty of increased reserve requirements. Several papers have been written attempting to identify at what point the economies of larger units are outweighed by the penalties of higher reserve requirements. Given the differences in methods and assumptions used, the conclusions in the papers are relatively consistent. The optimum size of the largest unit was found to be 4 to 6 percent,[23] 3 to 5 percent,[24] 8 to 16 percent,[25] and 7 to 10 percent[26] of a system's total installed capacity. Again, the varying assumptions and constraints used in each paper make questionable the application of these percentages to a specific situation.

The selection of the most efficient unit size for a system represents a balancing of incremental scale economies in generation against the aggregate effect of several penalties: reserve capacity effects, transmission cost effects, and the cost of temporary overcapacity as a result of building in advance of demand.

System forced-outage rates also have a great bearing on the level of reserves. If there were no forced outages, then reserve capacity would not be required to cover the unscheduled loss of a unit. Figure 4-2 shows the effect quite clearly. For a system of 200 identical units, a doubling of the forced-outage rate from 5 percent to 10 percent results in an increase in reserve requirements from 11.5 to 18.5 percent.[27]

The Federal Power Commission in its report, *Electric Generating Plant Availability*,[28] analyzed the effect of improvements in forced-outage rates on two systems. One system represented



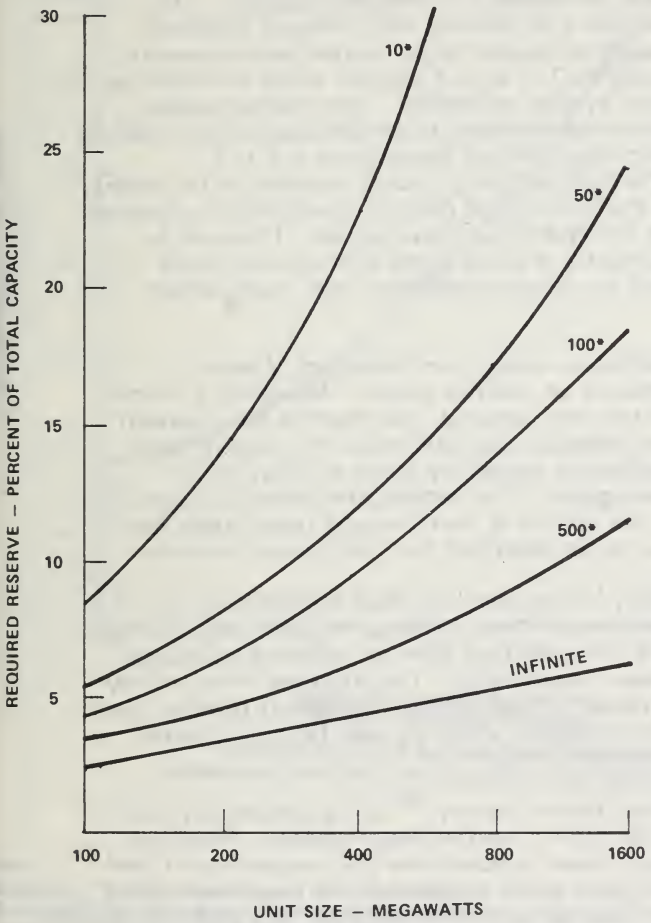
RESERVE REQUIREMENT VERSUS
SIZE OF CONNECTED SYSTEM

Source:
Mabuce, Estel M., Wikes, Richard L. and Boxerman, Stuart B., Generation Reserve Requirements, Sensitivity to Variations in System Parameters. IEEE Transactions on P.A. & S.

Figur

FORCED OUTAGE RESERVE FOR HYPOTHETICAL SYSTEMS OF SELECTED SIZES

For Combinations of Identical Units



* System Size in Gigawatts (1,000 Megawatts)

Reserve requirements will be higher if larger units are chosen as an alternative for smaller units, but the difference becomes less as the size of the system (the coordinated systems) increases.

Source:
Federal Power Commission, National Power Survey,
Washington D.C. Government Printing Office, October 1964

Figure 4 - 4

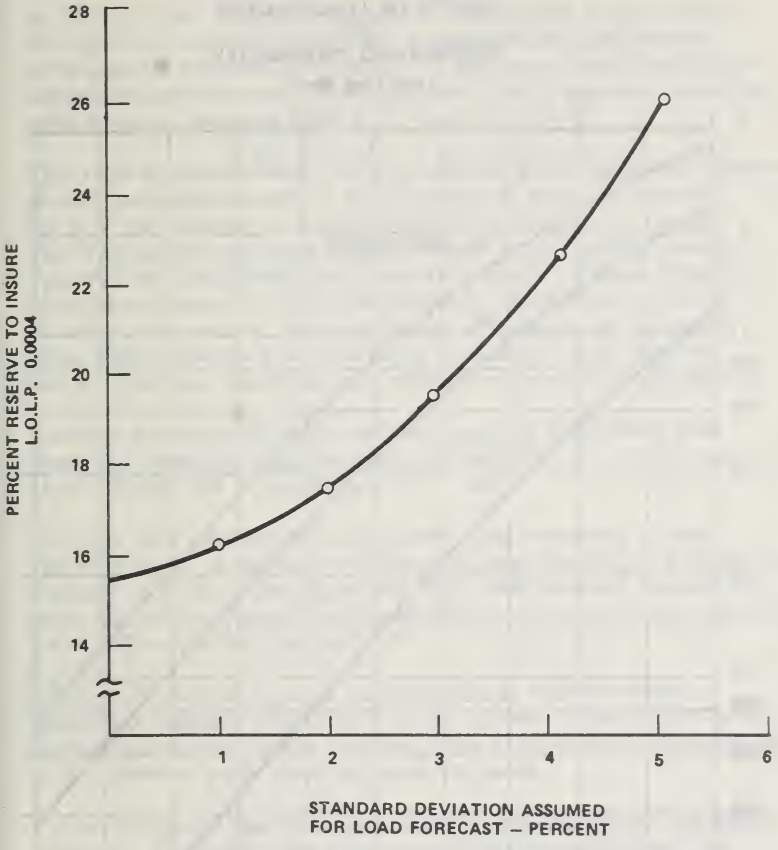
an actual group of utilities which operate in one geographical area, and which in 1980 will account for 5 to 6 percent of the total installed capacity in the United States. The other system was a single utility which in 1980 will represent 2 to 3 percent of the country's installed capacity. The results showed that a 10-percent improvement in forced-outage rates would allow the larger system to decrease its installed capacity by 1.5 to 1.2 percent while maintaining the same level of system reliability. The smaller system, with a 10-percent improvement in forced-outage rates, would be able to reduce its installed capacity by 1.6 to 1.2 percent.[29] The Federal Energy Administration in its report, *Improving the Productivity of Electric Powerplants*, obtained similar results using different approaches. It should be noted that the results of these types of studies are very much influenced by system generation mix, load pattern, and growth rate.

Mabuce,[30] also did an analysis of the effect of load-forecast uncertainty on reserve levels. Assuming a normal distribution of the peak demand, the effect of the standard deviation of the forecast distribution on the reserve level required to maintain a reliability index of 1 day in 10 years was investigated. The results are shown in figure 4-5. Quite clearly, the degree of load-forecast uncertainty has a large influence on the required level of system reserves.

Savage and Wofsy[31] analyzed the effect of load factor on reserve requirements. Their findings indicate that, as load factor improves, the required level of reserves increases, but not in a linear relationship. The increase in reliability when the load factor is lowered by 5 percent is greater than the decrease in reliability when the load factor increases 5 percent. See figure 4-6.

The 1970 National Power Survey,[32] using probability techniques, analyzed future reserve requirements. Separate calculations were made to determine the composition of total reserves required in order to quantify the requirements for forced outages, load-growth uncertainties, and peak maintenance. The results of the analyses for the 1990 conditions showed a national average reserve requirement of about 20 percent of peakload. Individual regional analyses varied within a range of 15 to 26 percent, reflecting anticipated differences in unit size, type and characteristics of generation, and characteristics of load.

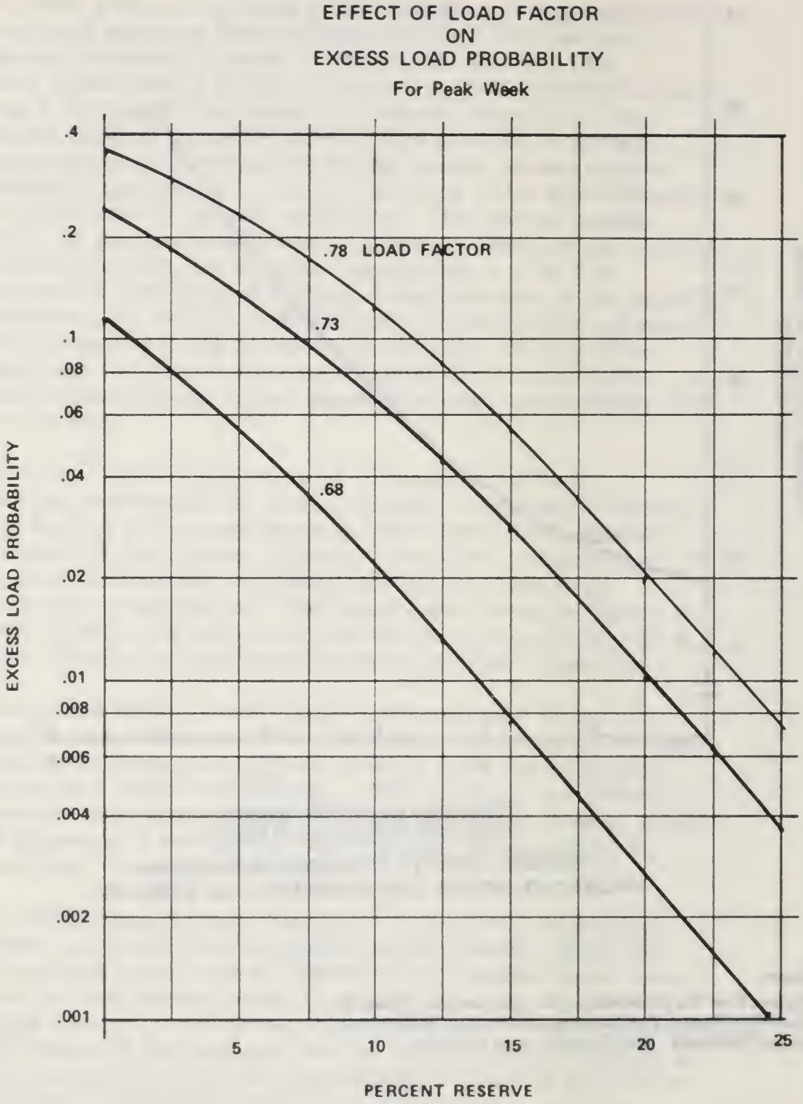
The reserves estimated to be needed in 1990 for forced outages varied between 9.2 and 12.8 percent, with a national average of about 11 percent.[33] Another paper concluded that a practical reserve limit for forced-outage protection would



PERCENT RESERVE REQUIREMENT VERSUS
ASSUMED STANDARD DEVIATION OF LOAD FORECAST

Source:
Mabuce, Estel M., Wikes, Richard L. and Boxerman, Stuart B., Generation Reserve Requirements, Sensitivity to Variations in System Parameters. IEEETransactions on P.A. & S.

Figure 4 - 5



Source:
Savage, N., and Wofsy, L.A., January 1975.
Peak Week Excess Load Probability. IEEE P.E.S.
Winter Meeting, January 1975 Paper No. C75019 – 5

Figu

be in the order of 8 to 9 percent.[34] Reserves required for load growth uncertainties were 4 to 7 percent regionally with about 5 percent nationally.[35] Reserve requirements for scheduled maintenance averaged less than 2 percent nationally, with regions varying from 0 to 7 percent.[36,37]

The 1970 *National Power Survey* estimates for required reserves do not include allowances for slippage of inservice dates for new generating and transmission facilities. In recent years slippage has been a major factor in difficulties many systems have experienced in meeting loads. These slippages have been caused by licensing delays, equipment troubles, construction delays, and manpower problems, all of which show the importance of providing sufficient lead times to ensure that new facilities are placed in service as scheduled.

Another work which analyzed two systems concluded that required reserves approach 10 percent after a system reaches about 45,000 MW in capacity.[38]

Utilities now usually provide generating reserves in the range of 15 to 25 percent of expected peak demand. Tables 4-1 through 4-4 show the projected 1975-1984 summer and winter peak demands, generating capabilities, and generating reserves by NERC reliability councils.[39]

Table 4-3 indicates, on a national basis, that the nine combined regions which have a net summer peak expect to be carrying reserve levels ranging from 21 percent to 27 percent of the summer peak over the next 10 years.

Table 4-4 gives the same information broken out by reliability council. The actual reserve considered necessary will be different for each individual system, as it is dependent on the generation mix, type of loads, and system configurations.[40,41]

REDUCING RESERVE REQUIREMENTS

Possible savings through the reduction of reserves must be considered in light of the possible penalties those savings might have in system reliability and in ability to meet load. We can calculate roughly the cost savings that would be realized if reserve level were to be decreased, for instance, from 20 percent to 15 percent. If, however, reduction in reserve levels results in a noticeable adverse effect on reliability and quality of service, what would public reaction be, and what would be the economic losses of a less reliable power supply? We believe studies should be addressed to answering these questions.

Table 4-1. GROWTH OF ELECTRIC DEMAND 1975–1984
AS PROJECTED BY REGIONAL RELIABILITY COUNCILS
1 APRIL 1975
CONTIGUOUS UNITED STATES

Year	Seven Council Group 1/	WSCC	ERCOT	Total MW 3/	Total Annual Increase (%)
		Projected Summer Peak Demand in Megawatts 2/			
1975	281,311	64,822	25,273	371,406	-
1976	302,256	68,917	27,552	398,725	7.36
1977	326,181	73,o11	30,102	429,894	7.82
1978	348,897	78,593	32,649	460,139	7.04
1979	372,710	82,975	35,320	490,005	6.71
1980	397,665	87,676	38,114	523,455	6.61
1981	423,745	92,605	40,953	557,303	6.47
1982	451,962	97,742	43,936	593,640	6.52
1983	481,626	103,395	46,975	631,996	6.46
1984	514,326	109,196	50,276	673,798	6.62
Average Annual Incr, Percent	6.94	5.97	7.94		6.84
		Projected Winter Peak Demand in Megawatts 2/			
1975-76	252,708	64,940	17,694	335,342	-
1976-77	272,511	69,116	19,336	360,963	7.64
1977-78	292,022	73,735	20,453	386,210	6.99
1978-79	312,243	78,572	22,238	413,053	6.95
1979-80	333,542	82,924	24,176	440,642	6.68
1980-81	355,760	87,722	26,103	469,585	6.57
1981-82	379,694	92,550	28,148	500,392	6.56
1982-83	405,011	97,850	30,234	533,095	6.54
1983-84	432,867	103,259	32,383	568,509	6.64
1984-85	462,421	108,971	34,817	606,209	6.63
Average Annual Incr. Percent	6.94	5.92	7.81		6.80

1/ Summation of regional estimates submitted by ECAR, MAAC, MAIN, MARCA, NPCC, SERC, SPP.

2/ These are non-coincident totals.

3/ Excludes that portion of the loads of small systems within the Council areas not supplied by Council members. The load excluded is estimated to be less than 2 percent of the total.

Table 4-2. GROWTH OF GENERATING CAPABILITY 1975–1984 AS PROJECTED BY REGIONAL RELIABILITY COUNCILS 1 APRIL 1975 CONTIGUOUS UNITED STATES

Year	Select Council Group 1/	WSCC	ERCOT	Total MW	Total Annual Increase (%)
			Projected Megawatt Capability at Time of Summer Peak		
1975	355,566	82,030	32,873	470,469	-
1976	378,208	88,389	34,226	500,823	6.45
1977	399,521	94,334	36,919	530,774	5.98
1978	421,103	100,976	39,652	561,731	5.83
1979	447,333	105,688	42,148	595,669	6.04
1980	472,675	113,102	46,505	632,282	6.15
1981	506,134	119,618	50,370	676,122	6.93
1982	543,995	124,740	54,749	723,484	7.00
1983	572,398	135,463	57,068	764,929	5.73
1984	611,524	143,988	59,288	814,800	6.52
Average Annual Incr. Percent	6.21	6.46	6.79		6.29
			Projected Megawatt Capability at Time of Winter Peak		
1975-76	373,306	83,307	33,981	491,094	-
1976-77	392,637	90,098	34,976	517,711	5.42
1977-78	416,255	95,691	38,841	550,787	6.39
1978-79	437,087	101,201	40,402	578,690	5.07
1979-80	461,014	107,522	42,778	611,314	5.64
1980-81	492,215	113,788	47,488	653,491	6.90
1981-82	520,692	120,202	50,449	691,343	5.79
1982-83	560,702	129,902	54,890	745,494	7.83
1983-84	586,600	136,279	57,068	779,947	4.62
1984-85	627,204	144,227	59,288	830,719	6.51
Average Annual Incr. Percent	5.93	6.22	6.42		6.02

1/ Summation of regional estimates submitted by ECAR, MAAC, MAIN, MARCA, NPCC, SERC, SPP.

2/ Excludes capability of small systems, within Council boundaries but not members of Councils. The capability excluded is estimated to be about 2 percent of the total.

Source: Reproduced from FPC News Release No. 21520, 30 June 1975, Table 2

Table 4-3. SUMMARY OF GENERATING RESERVES PROJECTED BY REGIONAL RELIABILITY COUNCILS AS OF 1 APRIL 1975 CONTIGUOUS UNITED STATES

Year	Seven Council Group 1/	WSCC	ERCOT	Total
		Percent Reserves 2/		
		At Time of Summer Peak Load		
1975	26.40	26.55	30.07	26.67
1976	25.13	28.25	24.22	25.61
1977	22.48	28.15	22.65	23.47
1978	20.70	28.48	21.45	22.08
1979	20.16	27.37	19.33	21.32
1980	18.86	29.00	22.02	20.79
1981	19.44	29.17	22.99	21.32
1982	20.36	27.62	24.61	21.87
1983	18.85	31.02	21.49	21.03
1984	18.90	31.86	17.93	20.93
		At Time of Winter Peak Load		
1975-76	47.72	29.05	92.05	46.45
1976-77	44.08	30.36	80.89	43.42
1977-78	42.54	29.78	89.90	42.61
1978-79	39.98	28.80	81.68	40.10
1979-80	38.22	29.66	76.94	38.73
1980-81	38.36	29.71	81.93	39.16
1981-82	37.13	29.88	79.23	38.16
1982-83	38.44	32.76	81.55	39.84
1983-84	35.52	31.98	76.23	37.19
1984-85	35.63	32.35	70.28	37.04

1/ Based on total of estimated loads and capacities of the seven inter-connected councils: ECAR, MAAC, MAIN, MARCA, NPCC, SERC, SPP.

2/ Reserve is the difference between the capability installed at the time of peak load and the peak load, expressed as a percentage of the peak load.

Source: Reproduced from FPC News Release No. 21520, 30 June 1975, Table 3

Table 4-4. **PROJECTED GENERATION RESERVES[1]**
FOR THE REGIONAL ELECTRIC RELIABILITY COUNCILS
CONTIGUOUS UNITED STATES
(PERCENT)

Year	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SWPP	WSCC
				At Time of Summer Peak Load					
1975	29.21	30.07	30.79	13.26	30.66	42.88	23.42	18.93	26.55
1976	29.18	24.22	25.46	13.28	31.06	40.40	23.57	15.73	28.25
1977	25.70	22.65	26.69	9.52	29.63	37.35	21.38	11.39	28.15
1978	22.64	21.45	23.25	10.89	25.14	31.49	20.67	12.84	28.48
1979	21.46	19.33	21.26	13.34	30.72	30.55	19.16	12.28	27.37
1980	20.99	22.02	19.29	11.24	32.13	27.63	16.46	14.78	29.00
1981	20.33	22.99	21.48	12.14	30.86	29.47	18.37	12.56	29.17
1982	18.30	24.61	26.90	13.44	30.52	30.17	18.64	16.40	27.62
1983	15.53	21.49	23.23	13.71	27.24	30.76	17.07	16.24	31.02
1984	15.96	17.93	23.90	16.43	27.19	28.71	17.08	15.11	31.86
Average Summer Reserve Margin (%)	21.93	22.68	24.23	12.72	29.52	32.94	19.58	14.63	28.75
				At Time of Winter Peak Load					
1975-76	44.29	92.05	65.31	53.75	47.20	52.45	33.38	69.01	29.05
1976-77	40.28	80.89	58.33	46.69	41.63	50.16	33.38	61.83	30.36
1977-78	37.59	89.90	59.43	48.49	41.49	44.50	32.97	57.90	29.78
1978-79	32.16	81.68	53.59	51.59	40.68	42.80	29.03	61.80	28.80
1979-80	31.64	76.94	50.38	53.15	43.99	38.35	26.16	59.87	29.66
1980-81	30.56	81.93	51.71	50.72	43.64	39.83	26.50	61.62	29.71
1981-82	29.42	79.23	48.32	51.55	42.20	34.98	26.97	59.83	29.88
1982-83	27.72	81.55	54.16	55.83	42.42	37.65	25.96	66.10	32.76
1983-84	24.49	76.23	50.18	51.32	38.21	32.31	25.00	63.28	31.98
1984-85	24.16	70.28	48.12	54.59	37.06	30.18	26.43	62.31	32.35
Average Winter Reserve Margin (%)	32.23	81.07	53.95	51.77	41.85	40.32	28.58	62.36	30.43

1/ Excludes inter-regional purchases and sales of capacity.

Source: Reproduced from FPC News Release No. 21520, 30 June 1975, Table 4

While peakload growth is immediately responsive to a number of factors, generating capability growth can be decreased quickly but cannot be increased significantly on short notice. Utilities should be cautious in curtailing construction plans on the basis of current decreases in projected load in order to avoid future power shortages.

Reductions in generating reserves must also consider the reliability and capacity of the associated transmission network. A completely reliable generating unit is of little benefit if there is no available transmission capability to carry the power to the load. One of the objectives of the National Electric Reliability Council is to provide guidelines for doing load flow analyses and system reliability studies. In this way, comparable results will be obtained, and exchange and interpretation of data will be facilitated.

Ringlee[42] analyzed the causes of disturbances in the bulk power supply systems as reported to the FPC under Order No. 311-1[43] for the years 1967 through 1973. The results are quite interesting:[44]

a. More than one-fourth of all the disturbances were related to failures of substation high-voltage power equipment.

b. More than one-sixth of the events were either initiated or compounded by protection, communication, or control subsystem misoperation or failure.

Five percent of other outages were initiated in or from generation equipment. This indicates that improvements in bulk power supply reliability would be accomplished best by improving substation performance, rather than by increasing generation reserves. It also indicates that present generating reserve levels provide a degree of reliability more than commensurate with other segments of the power supply sector. Also, these findings support a general desire by utility operators to have a substantial amount of generating capacity as near as possible to load centers in order to minimize exposure to transmission system and substation problems.

It is difficult to quantify the savings achievable through lower reserve levels that might be permitted by the completion of a national power grid system. We have calculated the savings from a reduction of reserve levels of one percentage point below the levels now planned over the next 10 years as shown in table 4-5. In table 4-6 we have calculated the savings if utilities were to reduce reserve levels to an overall average of 15 percent. A national level of reserves

Table 4-5. SAVINGS DUE TO A 1-PERCENTAGE POINT REDUCTION IN RESERVES (UNITED STATES)

Year	(1) Projected Summer Peak Demand (MW)[1]	(2) Planned Reserves (% of Peak)[2]	(3) Reduced Reserves (% of Peak) (2) - (1.0)	(4) Planned Summer Capacity (MW)[3]	(5) Reduced Summer Capacity (MW) (1) x (3)	(6) Planned Additions (MW)[4]	(7) Reduced Additions (MW)	(8) Capacity Savings (MW) (6) - (7)	(9) Capital Savings ($000)[5]	(10) Present Worth of Savings ($000)[6]	(11) Cumulative Savings ($000)
1975	371,406	26.67	-	470,469	470,469	-	-	-			
1976	398,725	25.61	24.61	500,823	496,851	30,354	26,382	3,972	2,161,000	2,161,000	2,161,000
1977	429,894	23.47	22.47	530,774	526,491	29,951	29,640	311	169,000	154,000	2,315,000
1978	460,139	22.08	21.08	561,731	557,136	30,957	30,645	312	170,000	142,000	2,457,000
1979	490,005	21.56	20.56	595,669	590,750	33,938	33,614	324	176,000	134,000	2,591,000
1980	523,455	20.79	19.79	632,282	627,047	36,613	36,297	316	172,000	120,000	2,711,000
1981	557,303	21.32	20.32	676,122	670,547	43,840	43,500	340	185,000	118,000	2,829,000
1982	593,640	21.87	20.87	723,484	717,533	47,362	46,986	376	205,000	119,000	2,948,000
1983	631,996	21.03	20.03	764,929	758,585	41,445	41,052	393	214,000	113,000	3,061,000
1984	673,798	20.93	19.93	814,800	808,086	49,871	49,501	370	201,000	97,000	3,158,000

---

[1] "FPC Issues Staff Summary of Electric Utility Expansion Plans for 1975-1984," table 1.
[2] Ibid., table 3.
[3] Ibid., table 2.
[4] Ibid., table C-10-9.
[5] Average NERC regional coal generation costs $544./kW. If it is assumed that
[6] some nuclear generation would also be saved in reducing reserves, the average
coal/nuclear capacity cost would rise to about 559 per kW by 1984. Capacity
savings would then be about 2 percent greater than shown.
Discount rate 9.5 percent.

Note: Col. (11) will, in each year, be the sum of the previous year's annual savings plus those of the current year.

Table 4-6. SAVINGS BY REDUCING RESERVE LEVELS TO 15 PERCENT IN 1976 (UNITED STATES)

Year	(1) Projected Summer Peak Demand (MW)[1]	(2) Planned Reserves (% of Peak)[2]	(3) Planned Summer Capacity (MW)[3]	(4) Reduced Summer Capacity (MW) (1) x 1.15	(5) Planned Additions (MW)[4]	(6) Reduced Additions (MW) (3) - (4)	(7) Capacity Savings (MW) (5) - (6)	(8) Capital Savings ($000)[5]	(9) Present Worth of Savings ($000)[6]	(10) Cumulative Savings ($000)
1975	371,406	26.67	470,469	470,469	-	-				
1976	398,725	25.61	500,823	470,469	30,354	-0-	30,354	16,513,000	16,513,000	16,513,000
1977	429,894	23.47	530,774	494,378	29,951	23,909	6,042	3,287,000	3,002,000	19,515,000
1978	460,139	22.08	561,731	529,160	30,957	34,782	(3,825)	(2,081,000)	(1,736,000)	17,779,000
1979	490,005	21.56	595,669	563,506	33,938	34,346	(408)	(222,000)	(169,000)	17,610,000
1980	523,455	20.79	632,282	601,973	36,613	38,467	(1,854)	(1,009,000)	(702,000)	16,908,000
1981	557,303	21.32	676,122	640,898	43,840	38,925	4,915	2,674,000	1,699,000	18,607,000
1982	593,640	21.87	723,484	682,686	47,362	41,788	5,574	3,032,000	1,759,000	20,366,000
1983	631,996	21.03	764,929	726,795	41,445	44,109	(2,664)	(1,449,000)	(768,000)	19,598,000
1984	673,798	20.93	814,800	774,868	49,871	48,073	1,798	978,000	473,000	20,071,000

---

[1] "FPC Issues Staff Summary of Electric Utility Expansion Plans for 1975-1984." table 1.

[2] Ibid., table 3.

[3] Ibid., table 2.

[4] Ibid., table C-10-9.

[5] Average NERC regional coal generation costs $544/kW. If it is assumed that some nuclear generation would also be saved in reducing reserves, the average coal/nuclear capacity cost would rise to about 559 per kW by 1984. Capacity savings would then be about 2 percent greater than shown.

[6] Discount rate 9.5 percent.

of 15 percent would result in some areas having less than 15-percent reserves while others would have in excess of 15 percent.

One of the perceived benefits of a national grid is a lowering of reserve requirements throughout the United States. The preceding discussion has been an attempt to explain why reserves are necessary in the first place and to show what levels of reserves are felt to be necessary to cover the various contingencies.

Reserve requirements are additive--that is, the reserves required for load forecast uncertainty cannot be considered covered by the reserves for forced outages. Each area of uncertainty must be covered by its own reserves. One cannot say that forced-outage reserves of 8 percent will cover the 2 percent needed for weather unpredictability. Any decreases in reserves would have to be based on comprehensive study of a specific situation.

We have found no studies which examine the reserve requirements of the nation, assuming it is operated as a strongly interconnected single powerpool, as it theoretically would be with a fully developed national power grid system. Further, we have been able to find no computer models capable of handling the probability calculations for such a large system. We, therefore, have arrived at our findings of the potential effect of a national power grid on reserve requirements by analysis of the existing studies.

As powerpools become larger, there is a reduction in percentage reserves required but at a decreasing rate. At a level of about 15-percent reserves, a curve of percentage reserves vs size of connected system, as shown in figure 4-3, tends to become nearly flat.

Thus, we believe that the existence of a national grid would not allow utilities large reductions in reserves on an overall national basis. The possible savings of capacity would probably be in the order of 1 to 3 percent. It is likely that utilities' financial requirements will have a much greater impact on future utility reserve levels and reliability of service than a national grid would.[45]

HOW MUCH RELIABILITY IS NEEDED?

We have discussed how utilities are now determining generation reserve requirements and that there is some informed opinion that reductions in reserves can safely be made. Related questions include: Is the "1-day loss of load in 10 years" a reasonable objective? Could the objective be lower, or should it be higher? Should there be different reliability objectives for different classes of customers, and would it be practicable to provide for such a distinction? To our knowledge, there has been no definitive investigation into these questions. There are regulatory and legal ramifications to these questions, which we discuss in chapter 8. To the extent that it may be found that generation reserves may be reduced by lowering loss-of-load objectives or providing different reliability standards for various classes of customers, potential benefits of a national power grid, or intermittent stages of interconnection, toward reducing reserve refinements, would be diminished.

■ FOOTNOTES TO CHAPTER 4

1 Meeks, James E. 1972. *Concentration in the electric power industry: the impact of antitrust policy*. Columbia Law Review 72. pp. 64-130. Breyer, Stephen G., and MacAvoy, Paul W. 1974. *Energy regulation by the Federal Power Commission*. Washington, D.C.: Brookings Institution. Baldwin, C. J. April 1966. Reserve sharing is primary benefit from power pooling. *Power Engineering*. pp. 59-51. Thomas, E. L., Holmes, J. G., and Schonhoff, C. C. April 1971. Experience with large supercritical units. *Combustion*.

2 Billington, R. *Power system reliability evaluation*. New York, New York: Gordon and Breach, Science Publishers. p. 230.

3 Casazza, J. A., and Hoffman, C. H. 1968. Relationship between pool size, unit size, and transmission requirements. *International Conference on Large High Tension Electric Systems*. p. 3.

4 Ibid., p. 3.

5 The generation mix of each untility must reflect not only the type of unit (fossil-fired, nuclear-fired, hydro, etc.), but also the amounts of each of the types as well as the pattern and sequence of unit size installed on the system. The proper combination of baseload, intermediate, and peaking generation is a subject unique to nearly every utility system in the country. Parameters influencing this combination are availability of capital resources, costs of generation equipment, fuel availability and costs, load factor of the particular utility, and outage experience of generating equipment on systems.

6 Conversation with Bonneville Power Administration staff.

7 The Bureau of National Affairs, Inc. July 17, 1975. Electric power: head of research group sees need for double production every 10 years. *Energy user's report*. Washington, D.C.

8 This has been a subject of much discussion recently. See Federal Power Commission. June 1975. Federal Power Commission issues staff summary of electric utility expansion plans for 1975-1984. *Federal Power Commission News Release*. Washington, D.C. Also see Kerenyi, A. O., Ronkay, F., Peto, J., Szendy, K., and Hadik, Z. June 1968. Effect of increasing the generating unit size on system interconnection tie lines. *International Conference on Large High Tension Electric Systems*.

9 The scheduling of maintenance is constrained by:
a. Availability of personnel.
b. Maintenance tools and equipment availability.
c. Allowable maintenance interval.
d. Amount of maintenance required.
e. Dispersion of system generating capability.

10 United States Nuclear Regulatory Commission. June 1975. *Coordination, competition, and regulation in the electric utility industry*. Economic Analysis Section, Office of Antitrust and Indemnity. NUREG-75/061. See also Holme, K., and Associates, Consultants. January 1970. *Coal resources for electric generation*. Washington, D.C.

11 National Electric Reliability Council. July 1975. *Review of overall reliability and adequacy of the North American bulk power systems*. (Fifth annual review.) A report by interregional review subcommittee of the Technical Advisory Committee. Princeton, New Jersey. p. 3. "In the past deficiencies in generating capacity often have been met by the installation of combustion turbines. This option is still open, but the unavailability of gas and the limited availability of oil make the use of such equipment vulnerable, even for peaking purposes. In addition, the leadtime for the installation of such capacity has now increased to as long as three years so that combustion turbines no longer constitute a fast option to meet unexpected load increases or delays in generating equipment installations."

12 Federal Power Commission. October 1964. *National power survey*. Washington, D.C., Government Printing Office. vol. II, p. 35-36.

13 For discussions of various methods, their advantages, and their shortcomings, see Federal Power Commission. October 1964. *National power survey*. Washington, D.C., Government Printing Office. Also see Billington, R., op cit. Also, Baldwin, C. J. March 1969. Probability calculation of generation reserves. *Westinghouse Engineer*.

14 Federal Power Commission. October 1964. *National power survey*. Washington, D.C., Government Printing Office. vol. II, p. 36.

15 Billington, R. op cit., p. 123.

16 This calculation is based on 250 working weekdays per year. Weekends and holidays are not included because these periods do not generally present an exposure to loss of load.

17 Savage, N., and Wofsy, L. A. January 1975. Peak week excess-load-probability. IEEE PES winter meeting; paper No. C75019-5. p. 2. "The index '1 day in 10 years,' as far as we can determine, is not based on any full scale study of reliability requirements and customer acceptance but has more or less come to be accepted as a convenient measure." Along these lines it should be noted that we have not found any definitive study of the economic costs and benefits of various degrees of electric system reliability. This would be an exceedingly difficult and nebulous task, but probably a worthwhile one in light of the costs of generating capacity.

18 Shipley, R. B., Patton, A. D., and Denison, J. S. Power reliability cost vs worth. *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-91, pp. 2204-2212. Also see accompanying discussions.

19 Roddis, Louis H. Remarks to American Public Power Association Power Supply Planning Committee as quoted in *Electrical Week*, February 3, 1975, p. 5.

20 When attempting to analyze the effects of various parameters on system reserve levels, many simplifying assumptions must be made to keep the analysis from getting bogged down in computations and refinements which would add greatly to the complexity of the analysis. Because of this, many analyses use systems with identical units, identical forced-outage rates, and so forth. While these assumptions may cause loss of precision, it is doubtful they cause much loss of accuracy in the conclusions. Only when an actual system is modeled and the parameters associated with that system are used can reasonably specific results be obtained, and only for that system. Because of this, meaningful quantitative data as to the exact amounts of economies obtainable through greater degrees of pooling and coordination are presently unavailable. Until published analyses of the regional and even larger levels of aggregation are available, these economies will remain unquantified.

21 Mabuce, Estel M., Wilks, Richard L., and Boxerman, Stuart B., Generation reserve requirements - sensitivity to variations in system parameters. *IEEE Paper C72 481-0*, p. 2. This paper deals with a hypothetical configuration representative of a regional coordinating group covering several states, including large and small utilities.

Figure 1 was developed by starting with a given generation mix and making all capacity additions with 600-MW units with 6-percent forced-outage rates. See also Baldwin, C. J. April 1966. Reserve sharing is primary benefit from power pooling. *Power Engineering*, p. 59.

22 Casazza, J. A., and Hoffman, C. H. op cit. Also, Falk, A. K., The effects of availability upon installed reserve requirements. *IEEE Transactions on PA&S*, vol. PAS 85, November 1966, pp. 1135-1144, paper 31 TP 66-8. Federal Power Commission. October 1964. *National power survey*. Washington, D.C., Government Printing Office. Baldwin, C. J. April 1966. Reserve sharing is primary benefit from power pooling. *Power Engineering*. pp. 59-61. Mabuce, et al, op cit.

23 Casazza, J. A., and Hoffman, C. H. 1968. op cit.

24 Paris, L., and Valtorta, M. June 1968. Planning the installation of large units in interconnected systems: relevant parameters and their relative influence. *Proceedings from International Conference on Large High Tension Electric Systems*.

25 Kerenyi, A. O., Ronkay, F., Peto, J., Szendy, K., and Hadik, Z. op cit.

26 Kirchmayer, L. K., Mellor, A. G., O'Mara, J. F., and Stevenson, J. R. August 1955. An investigation of the economic size of steam-electric generating units. *AIEE Transactions*, vol. 74, part III, pp. 600-614.

27 Falk, A. K. The effects of availability upon installed reserve requirements. *IEEE Transactions on PA&S*. vol. PAS 85, pp. 1135-1144, paper 31 TP 66-8. Also see Garver, L. L. Effective load carrying capability of generating units. *IEEE Transactions on PA&S*. vol. PAS-85, pp. 910-919, paper 31 TP 66-5.

28 Federal Power Commission. May 1975. *Electric generating plant availability*. Bureau of Power staff report. p. 29.

29 For general discussion of generating plant availability, see Federal Energy Administration. March 1975. *A report on improving the productivity of electric powerplants*. Washington, D.C., U.S. Government Printing Office. See also Federal Power Commission. May 1975. *Electric generating plant availability*. Bureau of Power staff report. The subject of the forced-outage rates and availabilities of units is a subject with ramifications throughout the electric power industry. One of the greatest industry economies-of-scale has been in the size of baseload generating plants. The technology associated with plants in the 800- to 1,500-MW unit size is relatively immature, and the plants, because of their complexities coupled with external constraints, often have not operated at the levels originally assumed when these units were planned. This

has caused utilities to carry more reserves than they would if the plants had performed as expected. It should be noted, however, that data on the reliability and economic performance of nuclear plants during the first quarter of 1975 show that they achieved an average capacity factor of 72.3 percent, compared to 42.9 percent for oil-fired plants and 56.6 percent for coal. See *Electrical World*. March 15, 1975. 1975 annual statistical report.

30 Mabuce, Estel M., Wilks, Richard L., and Boxerman, Stuart B., op cit.

31 Savage, N., and Wofsy, L. A. op cit.

32 Federal Power Commission. December 1971. *The 1970 national power survey*. Washington, D.C., Government Printing Office. p. I-18-9. "On a national basis, the Advisory Committee and Commission staff studies indicated near-identical figures. There were considerable differences, however, between Regional figures and the Regional components of the staff studies, probably because of differences in outlook and analytical methods used by the various study groups. For the sake of consistency, staff figures were used in this report." The regions of reference are the six regions used for study in the 1970 NPS.

33 Ibid. p. I-18-9. "Forced outage rates ranging from 3.6 percent for 350 mw units to 7.5 percent for 2,100 mw units and above were used in the study. These rates are lower than those now being experienced but improvement is anticipated.... A significant factor in the regional variation in reserves required for forced outages was the proposed size of steam-electric units with respect to peak load. Larger unit sizes, when related to a given system size, inherently require larger reserves to provide a given standard of reliability. The composition of the total capacity by types of generation was also an important factor. Forced outages, for example, are greater for thermal plants than for hydro-electric plants and are greater for a coal-fired plant."

34 Falk, A. K., op cit.

35 Federal Power Commission. *The 1970 National Power Survey*. p. I-18-9.

36 Ibid., p. I-18-9.

37 This report contains some discussion as to the different levels of reserves in the National Electric Reliability Council regions and explanations as to whether or not those levels are considered adequate.

38 Baldwin, C. J. op cit.

39 Federal Power Commission. June 1975. Federal Power Commission issues staff summary of electric utility expansion plans for 1975-1984. *Federal Power Commission News Release*. Washington, D.C.

40 Ibid., p. 5. "It is appropriate for attention to be directed to several of the regions within the 7-Council group. Table 4 shows the individual council reserves with no adjustments for purchases or sales of capacity between council areas. NPCC, MARCA and MAAC have reserves that are entirely satisfactory. NPCC especially, because of the seasonal diversity between the New York (summer peak) and New England (winter peak) loads has reserves that are well above the minimum usually considered necessary for adequate reliability. MARCA's reserves also appear fully adequate. MAAC, which is for all intents and purposes the highly integrated Pennsylvania-New Jersey-Maryland power pool, also has reserves that should permit reliable operation. ECAR, which numbers several power pools among its 26 members, is favored by some seasonal load diversity among the member systems and appears to be in a reasonably satisfactory position through the summer of 1981. From the summer of 1982 on, ECAR's reserves are significantly less than for the preceding years; although the 1983 and 1984 summer reserves are not considered critical they are at the low end of the usual scale. In emergencies, ECAR could obtain support from the Ontario (Canada) system, from MAAC, from SERC and from MAIN through direct interconnections, and possibly from other regions via wheeling arrangements.

"SWPP and MAIN are the two council regions which have the lowest reserves for the period 1975-84. MAIN's reserves are less than 14 percent for the entire period, and drop to 9.51 percent in the summer of 1977. MAIN's winter reserves are sufficiently large that adequate maintenance can be performed during the winter periods, to reduce the probability of forced outages in the summer.

"However, the summer reserves, even if the generating units are highly reliable, appear to be critical. Support for MAIN systems could be made available by MARCA for all of the ten-year period and by ECAR for most of it. Southwest Power Pool, for the 1977-81 summers projects reserves below 15 percent. While 15 percent is not a magic number, reserves below that value indicate that reliability of power supply could well be less than desirable, and that review of the capacity planning would be in order. Reserves in the SERC area, as projected, do not indicate unreliable service, but do indicate that the possibility of unexpected load growth should bear careful watching."

41 "While the individual council margins of tables 3 and 4 are based on installed capacity and internal load within each region, without consideration of interregional capacity purchases which might be effected to improve

reserves, it appears that in some regions there is little room for complacency. For instance, MAIN's summer reserves, as discussed above, should be examined in the light of the possibility that loads may exceed those that have been forecast. If the load in the MAIN region were to be greater than that projected for each summer period by only 1 percent, MAIN's reserve margins neglecting purchases and sales would be as follows:

Year	Percent Reserve
1975	12.14
1976	12.16
1977	8.44
1978	9.79
1979	12.22
1980	10.14
1981	11.03
1982	12.31
1983	12.58
1984	15.27

These reserves, except for 1984, are well below what the MAIN systems indicate as the requirement for reliable service."

42 Ringlee, R. J., and Beck, J. W. December 1974. *An assessment of policies and technical factors affecting the degree of interconnection of electric utilities in the U.S.* Schenectady, New York: Power Technologies, Inc. appendix C.

43 This order requires a utility to report interruptions of electric power service caused by outage of any kV generating unit or of electric facilities operating at 69 kV or higher and resulting in load loss of 100 MW or more, or half of the annual system peakload, for 15 minutes or longer.

44 Ringlee, R. J., and Beck, J. W. op cit., p. C-4.

45 National Electric Reliability Council. March 1975. *A current view of the impact of postponements and cancellations on future electric bulk power supply in the United States.*

Chapter 5
TRANSMISSION

PURPOSES OF TRANSMISSION

Transmission has several functions in a power system. They may be classified as: (1) energy transfer, (2) system integration, and (3) interconnection.[1]

Energy transfer, both internally and through interconnection, can be done for several reasons other than just transport from generator to load. Firm energy and capacity--that is, electric energy and capacity which are intended to have assured availability to the customer to meet all or any agreed portion of his load--can allow a system or portion of a system with a relatively long-term deficiency to meet its capacity and energy requirements by purchasing them from another area which has an excess. This type of energy transfer allows participation in staggered plant construction and the marketing of any capacity in excess of a system's own requirements. Economy energy--that is, electric energy produced from a source in one system and substituted for energy that could have been produced by a less economical source in another system--can also be exchanged. The degree to which systems take advantage of economy energy depends upon how closely the system operators communicate with each other. Energy transfer can also include nonfirm energy, interchange energy, secondary energy, dump energy, and fuel-replacement energy.[2]

The system integration function of transmission results in a system having flexibility and strength to provide economical, reliable service. When emergency conditions exist, strong transmission assures that the network can absorb the initial stresses (unexpected powerflows, voltage surges, etc.) created by a disturbance and remain stable, and it provides, through interconnection, the capability for mutual assistance among the systems throughout the network. However, a transmission system cannot and should not substitute for a balanced bulk power supply of generation.[3]

Once electrical energy enters a transmission network, it loses its identity as to its generation source. Actual line flows are determined by the characteristics of the individual transmission lines and the geographical locations of generation and load. This displacement phenomenon makes it essential that electric power and energy flows be planned and dispatched on a systemwide basis.

---

1 See footnote references, end of chapter.

The capability of a transmission circuit increases approximately as the square of its rated voltage. If a transmission circuit can be built for higher-rated voltages at a cost that increases less than its transmission capability, then the higher voltage transmission becomes more economical. As a system grows, higher levels of transmission become attractive because of these economies.

"Because the equivalent reactance of a 765 kV line is but 1/5 that of a 345 kV line and only 1/30 that of a 138 kV line, a 765 kV line tying two points that are, say, 300 miles apart has an electric equivalent distance corresponding to only 60 miles at 345 kV and merely 10 miles at 138 kV. Therefore, an EHV network spreading over many hundreds of miles shrinks the electrical distances between various load centers and generating sources to the equivalence of only a few miles at lower voltages. The practical consequence of this is that a disturbance at one point of the interconnected network has a much greater effect many hundreds of miles away than it had in the past. This greater interdependence tends to accentuate the existence of transmission bottlenecks anywhere within the interconnected network and necessitates far greater coordination of planning and coordination among individual systems."[4]

Thus, utilities in pursuit of economies and increased reliability through longer and higher voltage interconnections, find themselves becoming even more interdependent.

THE NATION'S POWER SYSTEMS

Present Interconnections

At the present time, seven of the nine National Electric Reliability Councils are closely interconnected and have the ability to move large quantities of power from one area to another. These seven councils are:

- East Central Area Reliability Council (ECAR)
- Mid-Atlantic Area Council (MAAC)
- Mid-America Interpool Network (MAIN)
- Mid-Continent Area Reliability Coordination Agreement (MARCA)
- Northeast Power Coordinating Council (NPCC)
- Southeastern Electric Reliability Council (SERC)
- Southwest Power Pool (SPP)

The Electric Reliability Council of Texas (ERCOT) and the Western Systems Coordinating Council (WSCC) each operate isolated.

The existing extra-high-voltage (EHV) transmission lines in the United States are shown on the map, figure 5-1. Figure 5-2 shows diagrammatically the interregional ties in the United States.

Interregional ties between the United States and Canada and Mexico are shown on figure 5-3. Note that several interconnections of 230 kV and higher voltages are in operation between the United States and Canada. Three National Electric Reliability Council areas, those of NPCC, MARCA, and WSCC, include Canadian provinces. The winter-peaking Canadian utilities provide important opportunities for seasonal diversity interchange with summer-peaking utilities of the United States.

The Western Systems Coordinating Council is geographically the largest reliability council, covering 51 percent of the U.S. contiguous land area, and is the second largest in electric power resources. "It is necessary to view WSCC as comprised of four natural subregions that result from concentrations of natural resources and socio-economic influences which significantly affect the growth of population and the development of resources. These subregions are the Northwest Power Pool, the Rocky Mountain Power area, the New Mexico Power Pool and the Pacific Southwest area."[5] This council area presently has only normally open interconnections with the rest of the United States. The ties are relatively weak and, because of system operations, cannot be reliably closed.

We can say, therefore, that at present the United States has three separately operating electric systems which can be described as:

1. The Western States system (the WSCC region),
2. The ERCOT portion of Texas, and
3. The remainder of the United States.

Future Transmission

Through 1984 the electric utilities of the nation are planning extensive additions to the present systems of interregional interconnections. The planned additions for 1979 and 1984 are shown diagrammatically on figures 5-4 and 5-5. Figure 5-1 shows transmission additions planned for 1984 and 1994. In 1976 the WSCC and MARCA areas will be interconnected through a direct current tie that will have a relatively limited capacity of 100 MW. We do not characterize this as a major interregional tie in the context of a national power grid. Otherwise, the ties between already interconnected regions will be greatly strengthened by 1984, but WSCC and ERCOT will remain essentially isolated from the rest of the nation in 1984.

Ringlee and Beck[6] did an analysis of transmission requirements between 1973 and 2000 based on five scenarios:

1. High load growth--nuclear case--with continued generation expansion at current trend (i.e., dispersed generation siting near major loads).

2&3. High load growth--nuclear case--concentration of nuclear plants into major generating complexes (nuclear parks).

4. Medium load growth--concentration of baseload, fossil-fired generation at mine-mouth locations.

5. Low load growth--generation as in one above.[7]

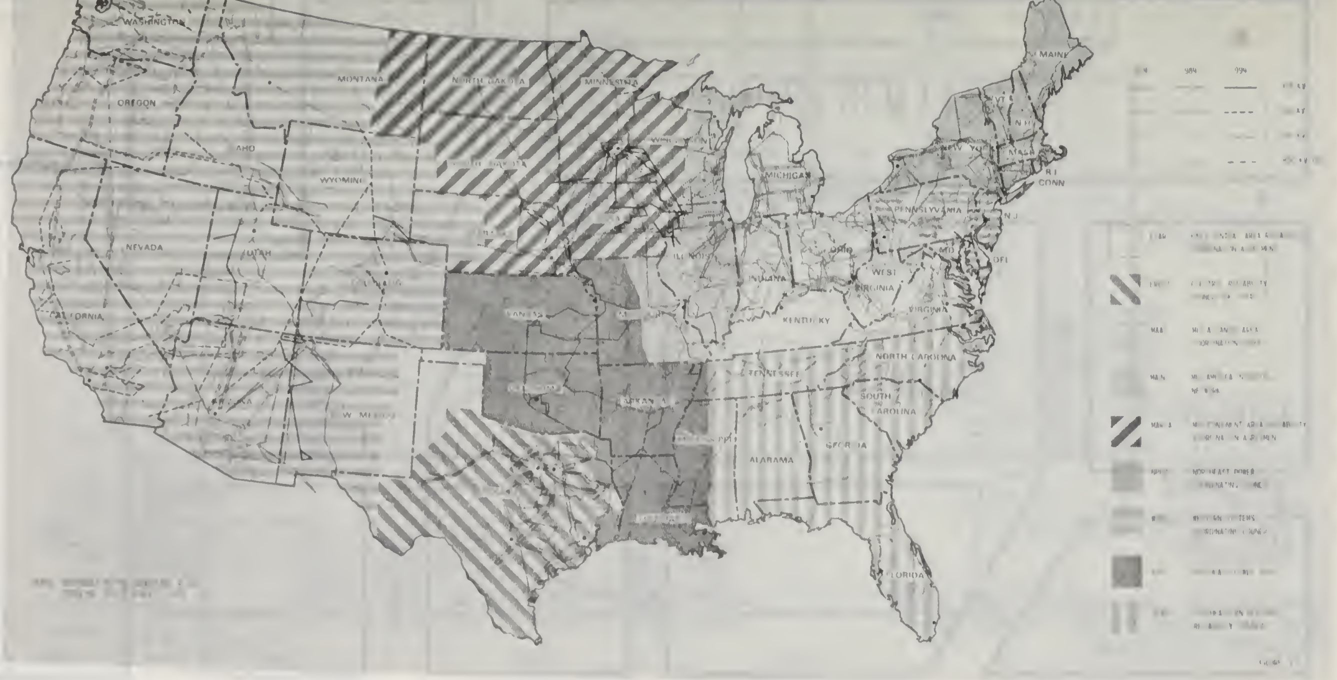
The results of the studies showed that approximately the same amount of transmission line additions (345 kV and above) were required for cases 1, 2, 3, and 4, varying from 110,500 to 116,700 miles. Case 1 required the fewest additions and was felt to reveal the efficiency of site selection and line routing which has taken place to this time. The low load growth scenario required only about one-third the additions of the other scenarios.

INTERREGIONAL POWER TRANSFERS

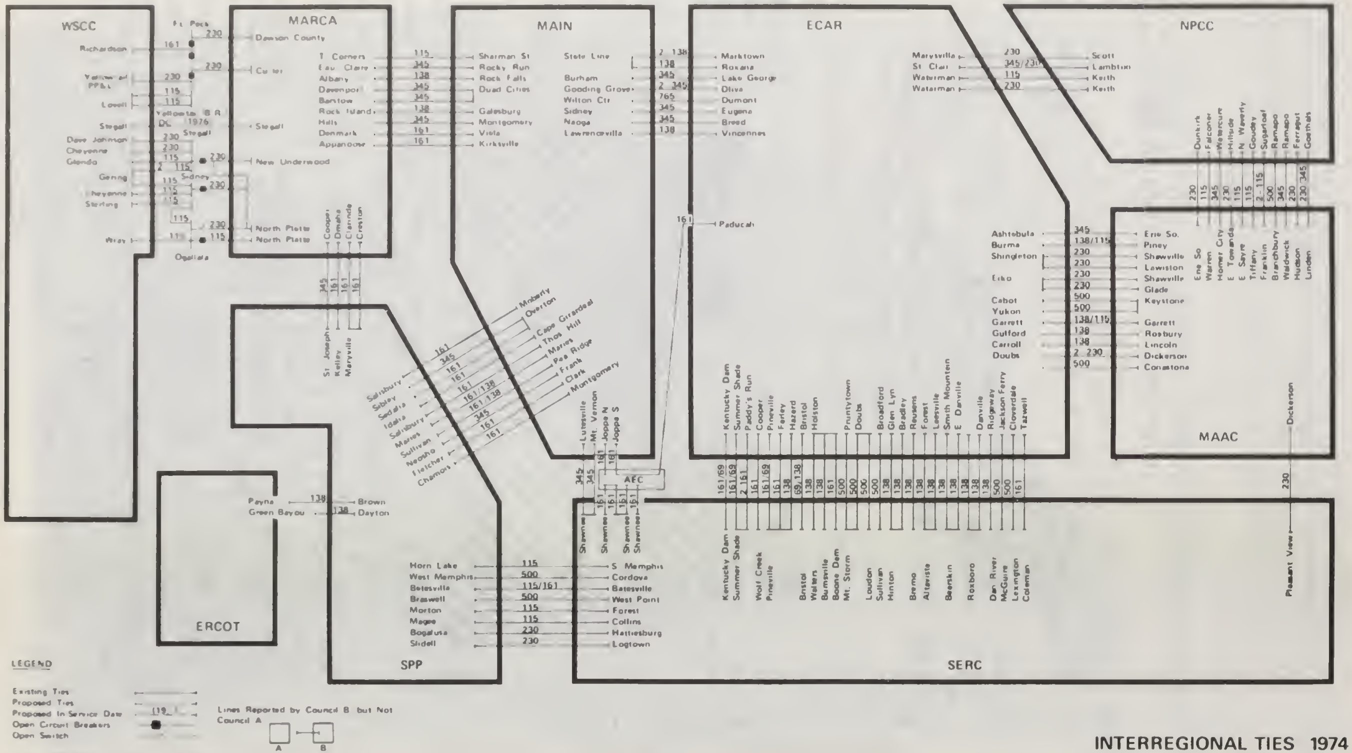
The shrinking world of electric systems was one of the primary reasons for the establishment of the National Electric Reliability Council (NERC),[8] with the objective "...further to augment the reliability and adequacy of bulk power supply in the electric utility systems of North America". It has devoted a great deal of effort toward prevention of any future cascading outages and widespread blackouts.

NERC has conducted multiregional simulation studies for selected future load levels covering the relevant portions of the large bulk power network, including the WSCC region where appropriate, to appraise more fully the interaction of significant facilities, power transfer capabilities, and the overall performance of the network.[9] These studies investigate in some detail power transfer capabilities between regions,[10] using two different bases:

1. All lines in service ignoring the possibility of a contingency; and,



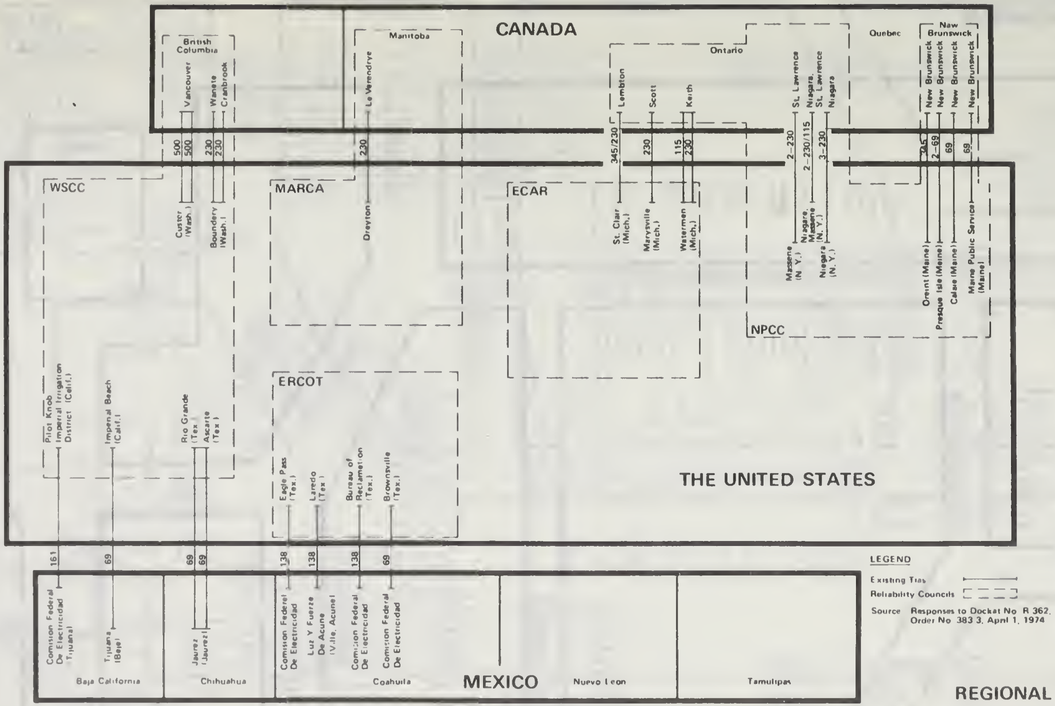
EHV AND UHV TRANSMISSION
EXISTING AND PLANNED 345 KV AND
HIGHER VOLTAGES 1974, 1984, AND 1994



INTERREGIONAL TIES 1974

Figure 5 - 2

Source Responses to Docket No. R 362
Order No. 383 3 April 1 1974

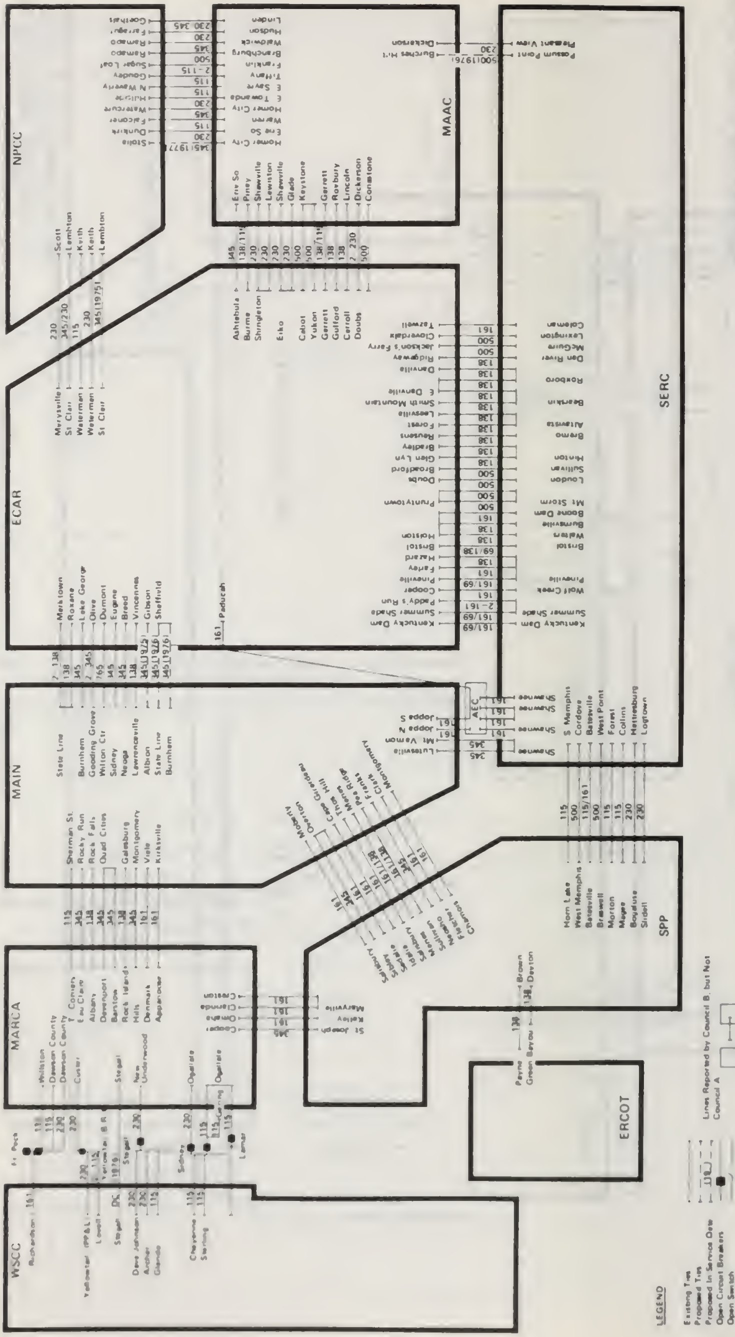


Source Responses to Docket No. R 362, Order No. 383 3, April 1, 1974

REGIONAL TRANSMISSION INTERCONNECTIONS WITH CANADA AND MEXICO-1974

Figure 5 · 3

Figure 5 3



INTERREGIONAL TIES 1979

Source: Responses to Docket No. R-362 Order No. 383-3, April 1, 1974

Figure 5 - 4

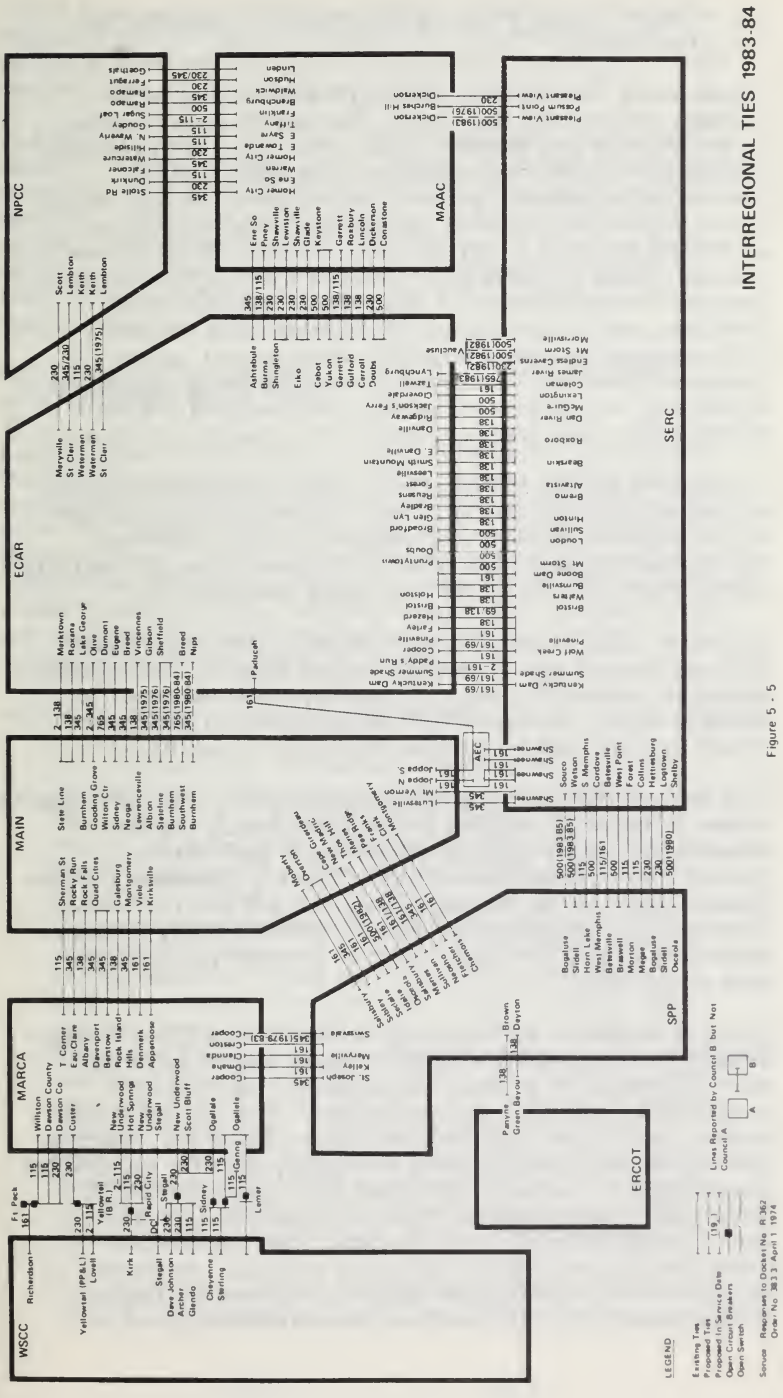

INTERREGIONAL TIES 1983-84
NPCC
MAAC
ECAR
SERC
MAIN
MARCA
WSCC
SPP
ERCOT
AEC
LEGEND
Existing Ties
Proposed Ties
Proposed In Service Date
Open Circuit Breakers
Open Switch
Lines Reported by Council B but Not Council A
A
B
Source: Responses to Docket No. R 362 Order No 383 3 April 1 1974
Figure 5 - 5

Figure 5 - 5

2. A major facility affecting the transfer in question out of service.

It was found that facilities limiting transfers may be on systems remote from the regions that are directly involved in the transfer and therefore may not be apparent in studies that do not include representation of at least a major portion of the entire interconnected network. In fact, much of the information obtained, pertaining to the interaction of the transmission facilities under the transfer conditions studied, could not have been obtained from regional investigations of smaller scope.[11] Analysis of load flow cases indicates that in some instances the removal of the limitations imposed by a single facility would permit greatly increased transfers. In several instances minor upgrading of existing facilities or the addition of a parallel line or transformer could greatly increase the capability to transfer.[12]

This points out two things: first, planning and coordination of transmission systems must be considered in view of their effect on other systems; and, second, greatly improved transmission systems can often be obtained through relatively minor improvements rather than major undertakings.

A similar study of the planned 1978 North American Power Systems showed significant differences from the 1973 system. Additions planned by the individual systems and pools to reliably supply estimated 1978 demands will in general result in increased transregional transfer capabilities.[13]

The nonsimultaneous interregional emergency transfer capabilities shown in the NERC studies are the incremental transfer capabilities remaining after allowance is made for the normal interregional powerflows. These incremental transfer capabilities must be carefully evaluated and used in analysis. They are not simultaneous. As with load diversity, transfer capability can be used only once, to transmit power in one way or the other.

We have compared the interregional emergency transfer capabilities found by NERC with the regional load diversities, after allowance for planned maintenance, that might be available for transfer between regions. The results of this analysis are shown diagrammatically in figure 5-6. We find that the existing interregional emergency transfer capabilities now exceed the seasonal load diversity, except in ERCOT, which has no interregional transfer capability. This situation is expected to exist also in 1980. There are insufficient data beyond 1980 for definitive analysis. However, with extensive transmission additions planned by 1990 and the likelihood that relative diversity will remain about as it now is or will decrease as noted in chapter 3, we expect that interregional emergency transfer capabilities will continue to exceed the diversities, except for ERCOT, which has no plans for interregional interconnections.[14]

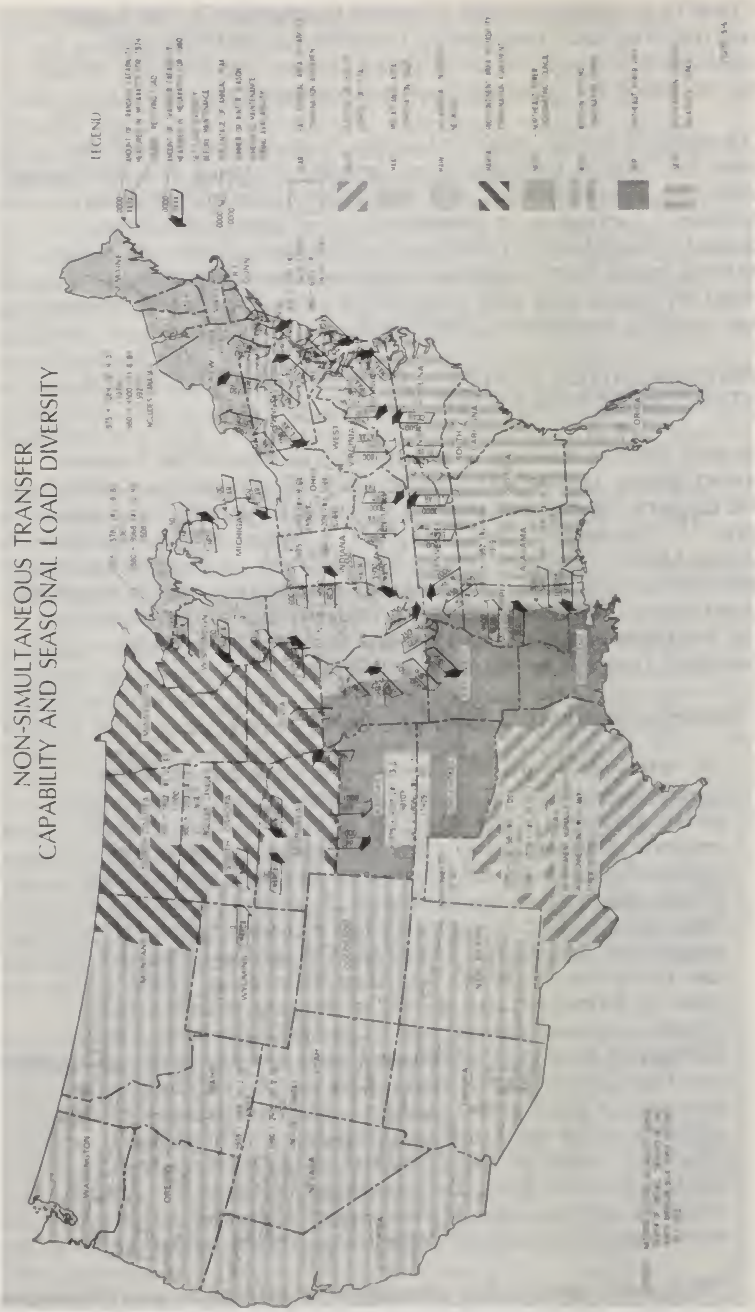
The electric power industry seems to be well aware of the need for, and is implementing, greater degrees of coordinated planning, development, and operation of its transmission systems. Increases in transmission voltage levels have caused a shrinkage in electrical distances. This has made utilities much more cognizant that what one does has an effect on others and that short-term independence of action may work to everyone's detriment.

WESTERN UNITED STATES - CENTRAL UNITED STATES INTERCONNECTION STUDY

Several studies dealing with interconnection of the Western United States (essentially the WSCC region) and the Central and Eastern United States interconnected systems have been done.[15] The most recent (the 1973), *Report of the Western United States: Central United States Study of Transmission Interconnection* (WUS-CUS study), concluded, on the basis of a cost-benefit analysis, that the construction of interconnection facilities of the degree needed to provide reliable operation is not economically feasible.

Following are excerpts from that report:

> "A relatively light transmission system between the western and central portions of the United States exists because of the sparsity of electric load in that region. Consequently, the few transmission interconnections which exist between the electric utilities of the west and of the central U.S. are of relatively low capacity and cannot provide a continuous interconnecting function. These East-West ties presently can be operated closed less than 20 percent of the time; previously, the ability to operate with the ties closed a reasonable portion of the time permitted the Bureau of Reclamation to make best use of energy surpluses available from time to time in the western and eastern portions of the Bureau system. The remaining time the utilities to the west, comprising 20 percent of the total U.S. electric load, operate as an interconnected system isolated from the remainder of the U.S. Those utilities with service areas on each side of the ties must operate two essentially independent systems.[16]
>
> "W/the AC approach a considerable influence was determined to be the unscheduled power which flows between electric


NON-SIMULTANEOUS TRANSFER
CAPABILITY AND SEASONAL LOAD DIVERSITY
LEGEND
MAINE
MICHIGAN
OHIO
INDIANA
WEST VIRGINIA
ALABAMA
WYOMING
UTAH
OREGON

> systems. This flow plus the expected emergency power burden require that the interconnecting voltage be at least 765 kv and connected at both the western & eastern ends at very high capacity locations on the existing systems. This requirement means that the lines would extend from the west coast or nearly so to points on or in the vicinity of the Mississippi River. . . . The nominal length of each such interconnection was judged to be roughly 1,900 miles.
>
> "If just one East-West 765 kv AC interconnection were built, the consequence of that line tripping on the integrity of the affected regions makes this alternative unacceptable. Such a disturbance would be anticipated to average 2 to 3 times per month.
>
> "Two such AC interconnections appear to be workable and would provide a maximum firm transfer of about 2500 MW. With unscheduled power flow ranging up to 1300 MW, 1200 MW firm transfer capability would remain available for scheduling.[17]
>
> "Using DC transmission, unscheduled power flow would not be a problem because operation of the western systems would be asynchronous with the eastern systems. Here a single bipolar ± 400 kv DC interconnection would perform satisfactorily."[18]

The study then analyzed the costs and benefits associated with the ac intertie and the dc intertie.[19]

		Millions	Benefit/Cost
Approach	Cost	Benefits	Ratio
ac	1,500	345	0.23
dc	365	312	0.85

> "In lieu of these accelerated interconnections programs, it appears that large power plant developments and transmission systems now being considered for the coal fields in Montana, Wyoming, and North Dakota, and major generating and transmission facilities being contemplated elsewhere in or near the sparsely developed area, will offer an opportunity for evolutionary development of the interconnections to take place. These interconnections would likely be 345 kv AC or higher, but more numerous, and shorter than the interconnections in the accelerated 756 kv plan. Such an evolutionary approach provides an option which may be much less costly. The

> feasibility of this approach is based on the individual developments each having reserve transmission capacity built in for contingencies which will reduce the reserve transmission capacity required for interconnected operation. The feasibility will be furthered if the individual developments each dedicate a fraction of their transmission to carrying a portion of the unscheduled power flow. Arrangements would have to be devloped, however, to properly compensate the utilities dedicating such transmission capacity. This process in which strong intra-regional ties are developed as load grows prior to developing strong inter-regional ties has precedence in inter-regional interconnection programs elsewhere in this country. Of vital importance, now, is that all utilities responsible for the planning of generation and transmission facilities in these regions do so with an awareness of their potential involvement in an interconnection program and that a maximum effort be made to assure joint planning among these utilities.
>
> "The summarized conclusion is that, considering the benefits identified and quantified, an accelerated program to strongly interconnect the western electric systems to the electric systems in central United States will not support the substantial investment required.
>
> "In all of these considerations, environmental impact obviously is of a major interest. However, this study purposely avoided any effort at definitive routes, terminal locations, design, and correspondingly, impact on the environment. When an interconnection program is definitely contemplated, this matter plus many others must be studied in depth."[20]

While it is beyond the scope of this study to make a fully independent analysis of the conclusions of the WUS-CUS study, the results appear reasonable to us. We come to this finding based on the considerable experience of the senior members of our study team with planning and operation of power systems in the Western United States. However, we have undertaken to update the WUS-CUS benefit-cost analysis and report our findings in chapter 7. Of particular note, we believe any apparent benefits of WUS-CUS interconnection need to be compared with possibly mutually exclusive benefits of additional interconnections between the midwest United States and Canada, and between the Pacific Northwest and Pacific Southwest.

ERCOT-SPP INTERCONNECTION STUDY

The situation of ERCOT is somewhat different. It has several low-voltage ties with other regions which are operated normally open but can be closed in an emergency to furnish some protection in the immediate vicinity of the ties. Generally, these ties are inadequate for parallel operation of the ERCOT and neighboring systems, and assistance is provided by manual switching in the field to isolate some local loads onto the ties.[21] There is one generation project which consists of a split bus with two generators each connected normally to feed independently to ERCOT and SPP. The buses are so arranged that both generators can be fed either to SPP or to ERCOT without being in interstate operation.[22]

Having no interstate interconnections, therefore no interstate commerce, the ERCOT utilities are not subject to FPC jurisdiction.

In 1972 the Federal Power Commission's regional office in Texas did a study[23] which concluded that interconnection of ERCOT and SPP would enable ERCOT to reduce its reserves over the period from 1975 through 1980 and thereby achieve a net savings of $156 million at 1972 price levels.

Planned ERCOT and SPP generation and EHV facilities in several instances will be 35 miles or less apart, affording opportunities for interconnection. Three interconnections, at 345 kV or higher and representing a total of 300 miles of transmission, were felt by the FPC to provide 2,200 MVA of import capability.

A loss-of-load probability analysis was run which showed that ERCOT could, with interconnections with SPP and the resultant economies of scale, reduce its reserves an average of 3.1 percentage points from those levels required for isolated operation.

The FPC study did not include any detailed load flow or transient-stability studies to determine if the ties proposed were adequate to support the interconnection of the two systems and if additional internal transmission lines would be required to make interconnection practical.[24]

ERCOT's response to the study was: "The ERCOT Technical Advisory Committee has examined the preliminary report. Also, previous studies made by our members have been reviewed. The potential advantages and consequences of the suggested interconnections were also examined. Our review does not support the conclusions of the report. It is the opinion of

ERCOT technical representatives that interconnection of the two regions would, in fact, be detrimental from both service reliability and economic standpoints.

"Accordingly, ERCOT does not believe that the suggested interconnections would be beneficial to electric customers in ERCOT members' service areas."[25]

It is beyond the scope of this national power grid study to resolve the differences between the findings of the Federal Power Commission and the response of ERCOT. We do note, however, that the distances between the load centers of ERCOT and SWPP are relatively short, especially when compared with the distances between the Midwest and the Far West electric systems. Throughout the rest of the United States most utilities find interconnections to be beneficial and are planning additions to interregional interconnections, some covering distances greater than those involved between ERCOT and SPP. The FPC finding of possible benefits and the geographic factors involved lead us to believe that more detailed studies of an ERCOT-SPP interconnection would be justified.

EMERGENCY BACKUP

Utilities are facing difficulties in obtaining adequate financing to meet their capital requirements, especially for generation projects. Cheap and plentiful fuel is a thing of the past. Obtaining sites and meeting environmental requirements for generation projects is a major utility problem. There is uncertainty as to what the pattern of future electrical demand growth will be. With such difficult conditions, a national grid system could be of benefit in allowing emergency support of one troubled region by others (witness the "coal-by-wire" experience where electricity was delivered over regional interconnections from coal-fired generating plants to supply the Northeast's requirements during the oil-short winter of 1973-74).

Because of the postponement and cancellation of construction programs being announced by utilities, their previously planned generation reserves may be substantially decreased. If load growth continues at historical rates, these cutbacks of generation projects will have an impact on reserve levels, probably much greater than any accelerated interconnections might have. However, stronger interconnections could increase the amount of interregional emergency support that could be provided.

However, in the light of the ever-stronger transmission systems being planned and built in the United States, it is doubtful, in our opinion, that practicable acceleration of construction of this transmission system would provide benefits much greater than those expected from the now-planned systems.

It is interesting to note that the Southwest Power Pool now feels that economy energy exchanges are a thing of the past, a result of fuel availability. Now, if a utility has fuel, it is reluctant to use the fuel to supply energy to another system when it has no assurance that the fuel can be replaced. If an exchange were to take place, the receiving utility would have to take responsibility for replacing the fuel. However, if no fuel is available, the legal responsibility of the receiving utility would be of little consolation to the system without fuel. It is conceivable that, in times of great fuel scarcity, only those systems with excess hydroelectric energy, which could not be stored, would be willing to send energy to other systems. In this kind of a situation a national grid would not be very useful without some form of mandatory energy transfer provisions regulated in the national interest. In chapter 8, we examine regulatory aspects of a national grid.

WHEELING

The term "wheeling" refers to the transmission of electric power and energy by a system that is not either the source or destination of that power and energy. Any concept of a national power grid likely would involve some wheeling transactions unless it is envisioned that all required transmission will be owned by a single entity.

Electric power and energy move over transmission facilities by a process called displacement. Once generated, electric power and energy lose their identity and are intermixed with the other power and energy in a system. For planning purposes, the flows of power on individual transmission lines can be determined only by doing load-flow studies, which model the line parameters affecting the flow of power, for various types of contingencies (certain transmission lines out of service, different generator loadings and availabilities, etc.).

Wheeling is a useful technique when properly applied. A major benefit of wheeling is to avoid duplication of transmission facilities. Wheeling can permit small utilities to obtain the benefits of competitively priced power sources that may be located an appreciable distance from that utility's load centers. Or, wheeling can be a short-term arrangement using temporary surplus transmission capacity and thereby delay construction of an eventually needed transmission line.

However, wheeling should never be imposed on a system without first performing detailed load-flow analyses to determine the impact on the transmission system involved. Such studies might show resulting line loadings that are beyond acceptable levels. It might also be found that underlying transmission facilities would have to be strengthened to permit the indicated power flows.

Dispatching must also be considered. Imposition of a power flow on an electric system without full control by the local system dispatcher weakens his ability to respond to changing system conditions.

At the present time, the Federal Power Commission does not have the authority to order wheeling except on an emergency basis.[26] During the "coal-by-wire" situation in the Northeast in 1973-74, all wheeling was done on a voluntary basis. However, there was a good deal of dispute as to the proper methods of allocating costs and calculating just compensation.[27]

FOOTNOTES TO CHAPTER 5

1 Nagel, T. J. January 1972. The national grid--A misconception. *Public Utilities Fortnightly*. p. 34.

2 See Federal Power Commission. 1965. *Glossary of important power and rate terms, abbreviations, and units of measurement*. Prepared under direction of Interagency Committee on Water Resources.

3 National Electric Reliability Council. October 1974. *Review of overall adequacy and reliability of the North American Bulk Power Systems*. A report by the Interregional Review Subcommittee of the Technical Advisory Committee, Princeton, New Jersey. p. VI-3. Also, some regulatory agencies do not permit a utility to include capital investments made outside its service area in its rate base.

4 Federal Power Commission. December 1971. *The 1970 national power survey*. Washington, D.C., Government Printing Office. p. IV-2-7.

5 National Electric Reliability Council. April 1975. *National Electric Reliability Council 1974 annual report with reports from its regional councils*. Princeton, New Jersey. p. 28.

6 Ringlee, R. J., and Beck, J. W. December 1974. *An assessment of policies and technical factors affecting the degree of interconnection of electric utilities in the U.S.* Schenectady, New York: Power Technologies, Inc.

7 Ibid., p. VI-12.

8 Federal Power Commission. December 1971. *The 1970 national power survey.* Washington, D.C., Government Printing Office. p. I-17-14. "Intensive studies of the Northeast Power Failure in 1965 demonstrated that, within the then-existent technology, individual system conditions could and did affect the interconnected system well beyond the boundaries of the problem area. It became clear that area and regional planning and coordination on a scale and in a depth that had not been practiced theretofore was required for reliable operation."

9 National Electric Reliability Council, Multiregional Transmission Study Task Force of the Technical Advisory Committee. December 1973. *Multi-regional transmission study of power transfer capabilities of the 1973 bulk power interconnected network in NERC.* Princeton, New Jersey.

10 Ibid. Also, National Electric Reliability Council, Multiregional Transmission Study Task Force of the Technical Advisory Committee. October 1974. *Multiregional transmission study of power transfer capabilities of the 1978 bulk power interconnected network.* Princeton, New Jersey.

11 Ibid., p. III-1.

12 Ibid., p. III-2. "It must be pointed out, however, that in many instances those facilities which impose transregional power limitations do not necessarily impose limitations within the specific region under normal or contingency regional operation."

13 National Electric Reliability Council, Multiregional Transmission Study Task Force of the Technical Advisory Committee. October 1974. *Multiregional transmission study of power transfer capabilities of the 1978 bulk power interconnected network.* Princeton, New Jersey. p. III-1.

14 Electric Reliability Council of Texas. April 1975. *Response to Federal Power Commission, order No. 383-3, docket No. R-362.*

15 U.S. Dept. of the Interior, Bureau of Reclamation. February 1968. *Transmission study 190. Steering Committee Report.* Washington, D.C. Western Systems Coordinating Council (WSCC), Mid-Continent Area Power Planners (MAPP), Mid-American Interpool Network (MAIN), and East Central Area Reliability Agreement (ECAR). July 1969. *An appraisal of transmission study 190.* Mid-Continent Area Power Pool (MAPP), Missouri Basin Systems Group (MBSG), and Southwest Power Pool (SPP). December 1973. *Report of the western United States: central United States study of transmission interconnection.*

16 Mid-Continent Area Power Pool (MAPP), Missouri Basin Systems Group (MBSG), and Southwest Power Pool (SPP). December 1973. *Report of the western United States: central United States study of transmission interconnection.* p. B-1.
17 Ibid., p. B-2.
18 Ibid., p. B-3.
19 Ibid, pp. B-2, B-3.
20 Ibid.
21 Federal Power Commission. October 1972. *Study of proposed interconnection between Electric Reliability Council of Texas and Southwest Power Pool.* Staff Report. Fort Worth Regional Office. p. 18.
22 Ibid.
23 Ibid.
24 Ibid., p. 27.
25 Ibid., p. 64.
26 Federal Power Commission. November 1974. *Order No. 520: order amending part 32 of the regulations under the Federal Power Act; applications for Commission emergency authorization pursuant to section 202(c) of the Act.* Washington, D.C.
27 Federal Power Commission. August 1974. New England Power Pool Participant et al., Appalachian Power Company et al., Dockets No. RM74-2, E-8589, E-8550 et al. Order permitting withdrawal of petition for emergency relief (Docket No. E-8589), and accepting rate schedules, permitting withdrawal of rate schedules, disposing of procedural matters and terminating proceedings. Washington, D.C.

Chapter 6
TECHNOLOGICAL QUESTIONS

For the near future and in the long run, overhead EHV and UHV power transmission lines will be the primary method of transmitting large blocks of electric energy over intermediate and long distances. Direct current transmission will see application principally for long-distance transmission of large blocks of energy. Underground EHV transmission, because of its high cost, will see application primarily in high load density urban areas.

ADVANCED TRANSMISSION SYSTEMS

The way of the future seems to be in the direction of cryogenic systems of two types: cryoresistive and superconducting. These systems, because of estimated high cost and presently immature technology, probably will not be available until the 1990's, and even then their application will be limited to special situations which justify the large capital expenditure needed.

More exotic methods of energy transmission--microwave and lasers--have technologies which are in the embryonic stages, making their application unlikely before the year 2000.

It should be understood that all technologies, regardless of their maturity, are undergoing constant evolution and refinement.

ULTRA-HIGH VOLTAGE ALTERNATING CURRENT

Research demonstrates that operation at voltages between 1,100 kV and 1,300 kV is technically within reach after expected engineering refinements perfect insulation requirements, corona performance, and power density allowances.[1] Sufficient data has been gathered to allow the design of a power transmission system at this voltage. However, lines operating at such voltages may have as-yet-undetermined effects on nearby plants and animal life. The Electric Power Research Institute (EPRI) is sponsoring work by Westinghouse Electric Corporation and Pennsylvania State University on the biological influence of electric fields.[2] Should the EPRI research find that strong electric fields adversely affect the environment, the design of EHV and UHV lines will then require limiting the voltage induced in transmission rights-of-way. The results of these studies will not be available for a couple of years. Further discussion on physiological effects of high voltage transmission lines will be found in the CRS Environmental Policy Division's report, "A National Power Grid System and the Environment."

---

[1] See footnote references, end of chapter.

Present utility requirements are being met with transmission line voltages up to 765 kV. The first UHV line will probably be installed in the 1980's and will serve as an overlay for existing 500-kV transmission. Bonneville Power Administration (BPA) is building, and hopes to have energized by early 1978, a 2-mile-long 1,100-kV ac prototype transmission facility. With this facility, BPA hopes to prove out and refine the line design.

One of the problems associated with EHV and UHV transmission is the concentration of large blocks of power and the effect this has on the magnitude of short-circuit current that could occur on the underlying transmission. The hardware on the underlying transmission was not designed to withstand the levels of short-circuit current that would be available. The solution to this problem appears to be in the use of current-limiting devices which would protect the underlying systems.

The problem of subsynchronous resonance, a potentially serious one associated with the use of series compensating capacitors, is not felt to represent a serious impediment to long-line EHV and UHV transmission. At the present time there is no practical acceptable solution. However, a great deal of work is being done on the subject.

DIRECT CURRENT TRANSMISSION

The technology for dc transmission is available and is finding wider application. Direct current overhead transmission is most justified for long-distance applications--the economic "crossover point" with ac being about 400 miles.[3] The advantages of dc over ac are lower losses for a given line resistance, asynchronous capability, no stability problems, no reactive impedance effects in the line, and lower overhead line construction costs. However, the terminal equipment for dc is much more expensive and elaborate than for ac systems.

Direct current is also feasible, especially when underground, for transmitting large blocks of power into areas with high load density such as large metropolitan areas.

One limitation of dc is the lack of a suitable dc circuit breaker. Without this breaker, it is not feasible to tap dc lines to provide service to loads intermediate to the terminals. At present, three research projects are underway, and it is felt that a dc breaker will be developed for use in the 1980's.

The technologies of cryogenic systems appear to be very expensive, and there is no indication that they will become economically competitive except in very special applications. It is felt that even with the development of these technologies they will not find widespread application until the late 1990's or the year 2000. However, work is proceeding at a good pace and DC superconductors appear very promising.

CONTROL SYSTEMS

At present, the largest power networks being automatically controlled by single-control systems are regional or sub-regional in size. Power network control systems increase considerably in complexity as the network size increases. Network size, in this sense, includes the number and size of generating units, number, lengths, and voltages of transmission lines, number of load centers, and the size and nature of the geographic area, especially as this affects data and control signal communications. Power network control systems are also complicated by seasonally changing input-output patterns of generation and load.

Very large computers, high-speed and reliable communications channels, and, especially, highly complex computer programs are being required as larger powerpools with a central dispatching system are implemented. At this time, however, practicable control systems for a high-capacity, fully integrated national power grid are not fully developed, and we do not know of any organization working on such a system.

LARGE GENERATING UNITS

As pointed out in chapter 4, as a coordinated power system increases in size, it is theoretically possible to increase the size of the largest generating units in the system and still maintain the general reliability characteristics of the smaller system with smaller generators. The development of larger and more strongly interconnected systems suggests the desirability of larger generating units, perhaps in the 1,500-MW to 2,000-MW range, to obtain the economy of scale usually expected with larger units. At present, such large generators are not developed. Also, present large generating units in the 1,100-MW range have higher outage rates than smaller units, thus increasing system reserve requirements. There would be a tradeoff between the benefits of economy-of-scale and lower reliability of larger units. Until the reliability of larger units is improved, largely a technological problem, a national power grid would not likely provide any benefit from the use of larger, presumably lower cost, generating units.

COOLING WATER

In various parts of this study, potential benefits are shown that relate to optimizing generation plant siting. Especially noted are possible benefits from locating large amounts of generation near the coal resources of the West. However, large thermal generating plants require a considerable volume of water for condenser cooling, using conventional water-cooling methods. In general, the Rocky Mountain areas, where coal resources are most abundant, tend to be lacking in adequate cooling water supplies. An alternative to avoid the need for cooling water is the use of so called dry-type cooling towers.[4] Dry-type cooling towers are more expensive than water-cooling methods, and reduce powerplant efficiency, so have found few applications to date. Development of cost-effective dry-cooling tower systems may be an aid to establishing the practicality of many large-scale generating projects in the western coal resource areas.

FOOTNOTES TO CHAPTER 6

1 *Electric Forum,* a magazine for electric utilities. June 1975. p. 3.
2 *Electrical World*. EPRI analyzes biological impact. p. 46.
3 Friedlander. May 1975. Energy's hazy future. *Spectrum*. p. 39.
4 LaForest, James J., and Truax, Charles J. June 1975. Energy transmission...what lies ahead. *Electric Forum*. p. 3.
5 Reeder, H. C. March 1975. *Water supply and treatment facilities, city of Colorado Springs R. D. Nixon power plant*. CH2M HILL, Inc., Denver, Colorado. Appendix A.

Chapter 7
ECONOMIC CONSIDERATIONS

Economic factors determining the feasibility of strengthening the interconnections of the nation's bulk power transmission systems are discussed and evaluated in this chapter. The subject can be treated only in general terms because a specific and discrete grid upon which detailed and complete data may be developed must first be defined. The purpose here is to identify important economic considerations for decisions related to accelerated development of a national grid and to present some preliminary estimates of costs and benefits attendant to such development. There is not sufficient data developed within the scope of this study to present a conclusive analysis of the feasibility of additional regional interconnections or a fully developed national grid.

FOCUS OF THE ANALYSIS

The analyses of chapter 3 revealed that there is insufficient uncaptured load diversity to merit accelerating the completion of a national power grid. Most of the discernable load diversity is already interchanged, or it provides the opportunities for generator maintenance. Time-zone load diversity across the U.S. is small and relatively unpredictable because major weather systems influence electricity demand over more than one time zone. There is substantial day-night load diversity. It is used to a small extent in pumped storage; otherwise, there is little opportunity to capture it. Therefore, it provides no basis for developing a national grid.

The transmission analysis of chapter 5 revealed that there are three separately operating power grids of high capacity covering the eastern half of the U.S., the western half, and most of Texas. Thus, the majority of individual electric power supply systems in the U.S. are presently interconnected with other systems. The existence of and planned expansions of these subnational grids makes the superimposition of a high-voltage, high-capacity transmission network a technically unneeded approach to development of a national grid.

Significant gaps remain to be closed before the nation's power supply systems are fully interconnected. Interconnecting and strengthening the existing grids to form a full, operational national grid is a logical alternative to a superimposed system. Therefore, we will consider the interconnection of the WSCC with the MARCA system and the SPP and the ERCOT systems.

Within each of the reliability council areas there may be opportunities to use existing generating capacity more efficiently through the addition of segments of EHV transmission lines. Economic analyses of these specific installations would require a one-by-one evaluation in a detailed study of existing transmission systems, power flows, and system load and operating characteristics; this is beyond the scope of this overview study. However, only through such detailed analysis could a full and discrete national grid be specified. Once specified, a benefit/cost analysis could be made.

Lacking a load-diversity justification for specifying a full and discrete grid, we analysed the possible capital savings from reducing generation reserves. The assumption underlying these analyses is that the establishment and operation of a national grid may allow the amount of operating reserves to be reduced to a national average of about 15 to 18 percent of annual peakload without reducing reliability. The assumption is generalized and applied uniformly to all electric power systems in the nation. As discussed in chapter 4, specific studies of reserve requirements with a national power grid fully operational are needed to more precisely determine the level of reserves that would actually be required with a national grid. The possible capital savings from reduced reserves, if substantiated by further study, may provide motivation for completing the national grid by interconnecting the three subnational grids.

It is important to note some limitations inherent in our economic assessments of a national grid or subsets of a national grid based on the limited scope of this study.

First, no transmission lines with engineering design specifications are proposed or studied in detail. We have based our analyses on cost estimates only for transmission lines connecting general areas. These are order-of-magnitude estimates that do not take into account detailed locational or technical specifications.

Second, data on some benefits are either incomplete or not available.

Finally, the scope of this study is limited to consideration of generalized regional interconnections, to the exclusion of possible opportunities for additional intraregional power transfers. Assessment of cost savings of reserve reduction and considerations of national interconnections make no presumptions about specific interconnections or priorities as to which specific inter- or intraregional facility should be developed first.

COSTS AND BENEFITS: DISCUSSION

A national power grid could lead to increased costs of some facilities and operations but decreased costs of others. Net costs must be examined to determine the net benefit of a national power grid. The increased costs will be associated with the additional transmission lines required. The costs of completing and strengthening regional interconnections consist mainly of the costs of right-of-way acquisition, construction, and operation and maintenance of new facilities--including transmission lines, substations, and control facilities. Interconnected and coordinated operations on a national scale would require more extensive and complex communication and operational control equipment than are currently in use.

Reliable data are scarce on UHV transmission lines, and related equipment and right-of-way and construction costs vary from one geographic area to another. The cost estimates do not include specific considerations for complex communication and control equipment. Fully dependable cost estimates can only be made from specifications for the transmission system being evaluated.

In addition to the basic construction costs of developing regional interconnections, there would likely be other costs, largely site specific, that are impossible to estimate here. Transmission lines require rights-of-way (land use). Some right-of-way clearing through forests and some earthmoving would be required. Further, large overhead transmission lines invariably have continuous aesthetic impacts. The possible biological effects of transmitting extra- and ultra-high voltages are being studied now. The costs of mitigation of such effects, if any, are unknown at this time. Quantification of these environmental and other costs, without specifications about the regional interconnections, is an exercise at best. Reasonable estimates can be made only if a specific project is defined for study.

A final aspect of costs resulting from regional interconnections involves the regulation and coordination of operations of the electric power industry. It is likely that more regulatory effort would be directed toward all electric utilities after interconnection. However, the increased cost of such regulation cannot be known in advance.

Several benefits are possible from accelerated completion of a national grid: lower generating reserve capacity requirements at unreduced reliability standards because of reserve sharing and emergency power exchanges; lower operating costs because of economy energy transactions; lower capacity requirements because of diversity exchange and coordination of planned maintenance; lower overall generator construction and operating costs because of installation of fewer, but larger, more efficient units in locations where construction and operating costs are lower; and lower operating costs because of integrating predominantly steam systems with predominantly hydroelectric systems. Other possible benefits are conservation of nonrenewable energy resources and reduced environmental damage. Some of these possible benefits are more likely to be realized from the development of a national grid than others. Furthermore, the first three are more easily estimated than the rest. However, all of the cost estimates used in this analysis are order-of-magnitude and do not take into account specific facilities, terrain, local right-of-way values, and other related factors.

Generating Reserve Reduction

Some studies have indicated that generating reserve capacity, in terms of percentage of peakload, could be reduced from present levels.[1] Foregoing the investment in future generating plant to reduce reserves below present levels as loads grow could yield substantial savings. Reductions in reserve levels could derive from stronger interconnections, allowing reserve sharing and emergency power interchange with no reduction in reliability. Reductions could also derive from improving the reliability of generating equipment or from simply lowering the reliability standards from present levels. This latter basis for savings from reducing reserves does not require a national grid or strengthening interconnections and interutility operations.

Since it was not possible within the scope of this study to determine precisely the amount, if any, that reserves could be reduced due solely to stronger interconnections, we examined the economic effect of various assumptions regarding reduced reserve levels. Implicit in each assumption is that there would be no change in reliability. An estimate was then made of the amount of EHV and UHV transmission lines and related facilities that could be constructed from these capacity savings.

A reader may infer from this analysis that the indicated savings in reserves could result from building the amount of transmission facilities that could be constructed. No such direct relationship is intended in this analysis; however, there is a general relationship between possible savings from reducing reserves and a strengthening of transmission interconnection. No estimate was made of how much reliability may be altered nor of what value would be attached to the alteration.

---

[1] See footnote references, end of chapter.

Operating Cost Reduction

Interconnected power systems reduce total operating costs through economy energy transactions. For example, one system operating at a low load factor (using large, efficient baseload generators) may have substantially lower marginal costs of producing electric energy than another system. Economy energy sales, in this instance, would enable the first firm to utilize its equipment more fully and thereby earn more profits while allowing the second company to reduce its costs of providing energy to its customers. The savings from such exchanges are normally divided equally between the buyer and seller. Our studies indicate that most practicable economy energy transactions are already engaged in by utilities, and that few additional transactions would be made possible by interconnection. Thus, we have not examined additional benefits from this factor.

Diversity Exchange

Firm agreements to transfer diversity capacity from one region to another can allow each area to reduce its individual installed capacity by matching diverse loads with its neighbor system, as discussed in chapter 3.

Similarly--because of the long-accepted industry practice of tailoring planned maintenance to fit peak and offpeak load periods--two interconnected systems, all systems in a power-pool, or a fully interconnected group of systems usually coordinate schedules for planned maintenance. Our studies of diversity indicate that virtually all usable diversity exchanges are now being undertaken by the nation's utilities, and that little further benefit could be realized regardless of the number of additional interconnections. Therefore, except for our analyses of the ERCOT-SPP interconnection and the Western U.S.-Central U.S. interconnection, we have made no analysis of diversity benefits that might be obtained with a national grid.

Economies of Scale

Interconnection of electric power systems makes possible the service of larger and probably more diverse loads from any generation unit. Larger total loads incorporating wider diversity of individual loads provide a basis for installing larger generation plants. The design and operating characteristics of larger plants, coupled with appropriate loads, yield lower unit costs of generating power. Heat rates are lower so that unit fuel costs are lower than with alternate systems, as are unit labor costs and other unit costs of production. In addition, installation costs per unit of capacity are also generally lower. There would possibly be higher transmission costs. Net benefits must be the controlling consideration, however.

We have shown elsewhere in this study that the largest generator sizes now available are generally being installed now. Until very large generators are made more reliable, a further increase in size, with some assumed unit cost savings, would be largely offset by an increase in reserve requirements. Therefore, we have assigned no economy-of-scale benefits to constructing national interconnections beyond those already planned.

Lower Operating Costs Because of Integrating Hydroelectric and Steam-Powered Systems

Operating costs can be reduced in any two or more systems with different generating costs, especially where one of the systems is predominantly hydroelectric. Currently, the Pacific Northwest systems, still about 90-percent hydroelectric, interchange power on a seasonal basis with Pacific Southwest utilities, which are predominantly oil- and gas-fired systems. The result is beneficial to both of these subregions of the WSCC. A similar exchange is made between Ontario Hydro and systems in the NPCC region. The TVA and the SPP also exchange large blocks of power because of opposing peakloads in winter and summer.

Our studies show very little opportunity in the future for additional interchanges of this nature. Some such interchange may be possible if there is a strong transmission tie between the Midwest and Far West, and we have made an allowance for this in our analysis.

Other Interconnection Benefits

Conservation of certain unrenewable energy resources is one possible benefit of the interregional exchange of power. Electricity from nuclear-, coal-, or hydro-powered plants could be used to displace power that would otherwise be generated in gas- and oil-fired plants. Further, use of more efficient baseload generating units during economy interchange could reduce overall fuel consumption. The savings would depend upon offsetting losses in the transmission of energy. We have not attempted to quantify these elusive values here.

We have not tried to assign a monetary value to potential environmental damage that might be averted because of a lessened need for large new generating plants. The net environmental effect of a grid, considering land needed for transmission lines, could only be estimated after more detailed study.

COST ESTIMATES

We have estimated, in 1975 dollars, order-of-magnitude cost of certain transmission lines and generation plants for use in our preliminary examination of costs and benefits related to regional interconnections and reducing reserve margins. These cost estimates are for various facilities in the following groups:

- Coal generation (over 600 MW)
- Nuclear generation (over 600 MW)
- Peaking generation units
- Transmission lines

Construction cost estimates are in dollars per kW for generation plant and dollars per mile for transmission lines. Operation and maintenance cost estimates are in mills per kWh for generation plant and in dollars per mile for transmission lines. For coal and nuclear generation costs, a regional breakdown was developed. Appropriate annual fixed charges in percent of capital costs was estimated for each of the groups. Finally, we estimated the cost of the nuclear fuel cycle in mills per kilowatt-hour.

Derivation of Cost Estimates

The first seven data sources[2] provided dollar figures for construction costs and operation and maintenance (O&M) costs for generation plant and transmission lines. However, none of these costs was in 1975 dollars. Therefore, we converted the dollar costs into 1975 dollars using the *Handy-Whitman Index*. To apply numbers from the *Handy-Whitman Index*, it was first necessary to assume that the dollar figures given in the first seven sources represented the cost as of 1 January of that particular year, unless otherwise noted.

National index numbers were developed from the *Handy-Whitman Index* for both total transmission plant and total steam production plant using the above assumption. The index numbers, shown in table 7-1, were then applied to the source data to convert them to 1975 dollars. From the range of the 1975 dollar costs, we selected the most appropriate cost for each plant item. The original data, those data represented in 1975 dollars, and the values we chose for use in our economic analyses, are shown in table 7-2. Tables 7-3 and 7-4 summarize the dollar values for construction and O&M costs and the fixed charge rate we use in further analysis.

Table 7-1. DEVELOPMENT OF NATIONAL INDEXES FROM HANDY-WHITMAN

TOTAL TRANSMISSION PLANT

Division	1 Jan 1968	1 Jan 1969	1 July 1969	1 Jan 1975
N.A.	182	186	195	345
S.A.	185	192	203	362
N.C.	184	192	202	354
S.C.	189	195	204	369
Pl.	198	203	213	383
P.C.	189	194	203	361
U.S. simple average	187.8	193.7	203.3	362.3

TOTAL STEAM PRODUCTION PLANT

Division	1 Jan 1968	1 July 1969	1 Jan 1971	1 Jan 1973	1 Jan 1974	1 Jan 1975
N.A.	179	191	213	249	269	334
S.A.	180	192	212	247	265	332
N.C.	183	196	217	249	267	335
S.C.	179	190	210	241	258	321
Pl.	177	187	208	237	255	320
P.C.	183	196	215	247	264	329
U.S. simple average	180.2	186.8	212.5	245	263	328.5

INDEXES TO 1 JAN 1975

From	Transmission	Generation
1 Jan 1968	1.9290	1.8233
1 Jan 1969	1.8709	NA
1 July 1969	1.7820	1.7109
1 Jan 1971	NA	1.5459
1 Jan 1973	NA	1.3408
1 Jan 1974	NA	1.2491

NA = Not developed due to lack of data against which to apply the index

---

KEY
N.A. = North Atlantic
S.A. = South Atlantic
N.C. = North Central
S.C. = South Central
Pl. = Plateau
P.C. = Pacific Coast

COST ESTIMATES FROM SELECTED SOURCES

	Wash 1174-74	Savings from Rates	1970 Nat. Pwr. Survey	Sheehan	FPC Hydro. Pwr. Suppl.	In 1975 Dollars					Cost Selection
						Wash.	Savings	FPC NPS	Sheehan	FPC HPS	
GENERATION[1]											
Nuclear											
Capacity	433-520	431	300	275	165-200	540-650	538	464	369	282-342	540
O&M	.8	--	.32-.51	.5	.31-.42	1.0	--	.5-.79	.67	.53-.72	1.0
Coal											
Capacity	400-480	377	--	225	115-155	500-600	471	--	302	197-265	480
O&M	2.0	--	--	.5	.25-.37	2.5	--	--	.67	.43-.63	2.5
Steam Peaking											
Capacity	--	--	--	180-200	90-120	--	--	--	241-268	154-205	250
O&M	--	--	--	.3	.88-1.75	--	--	--	.4	1.5-2.99	2.0
Gas Turbine Peaking											
Simple Cycle:											
Capacity	--	117	80-100	90-100	80-90	--	146	125	121-134	137-154	150
O&M	--	--	--	.7-1.0	1.25-2.20	--	--	--	.94-1.34	2.14-3.76	1.3
Combined Cycle:											
Capacity	--	189	--	140-150	--	--	236	--	188-201	--	240
O&M	--	--	--	1.0-1.5	--	--	--	--	1.34-2.01	--	1.5
Diesel Peaking											
Capacity	--	--	100	--	90-125	--	--	155	--	154-214	160
O&M	--	--	--	--	5.33-6.85	--	--	--	--	9.12-11.72	10
Fixed Charges[2]											
Private	15	--	11.2	12	13.5-14.4	15	--	11.2	12	13.5-14.4	14
Federal	--	--	--	--	6.6-7.6	--	--	--	--	6.6-7.6	7.4
Nuclear Fuel Cycle[3]	3.02	--	1.4-1.9	--	1.35-1.5	3.77	--	2.16-2.94	--	1.35-1.5	3.0

	FPC Nat. Pwr. Survey	FPC Hydro. Pwr. Eval.	WUS-CUS	In 1975 Dollars			Cost Selection
				FPC NPS	FPC HPS	WUS-CUS	
TRANSMISSION[4]							
345 kV							
S/C:							
Capacity	--	52,800	--	--	101,900	--	110,000
O&M	--	410	--	--	730	--	750
D/C:							
Capacity	--	99,200	--	--	191,500	--	200,000
O&M	--	460	--	--	--	860	880
500 kV							
S/C:							
Capacity	116,000	115,600	--	216,920	223,100	--	230,000
O&M	--	520	--	-	926	--	930
765 kV							
S/C:							
Capacity	165,000	--	312,400	308,550	--	312,400	325,000
O&M	--	--	866	--	--	866	880
±400 kV							
S/C:							
Capacity	--	95,700	--	--	184,700	--	190,000
O&M	--	--	--	--	--	--	--
±600 kV							
S/C:							
Capacity	--	129,000	--	--	248,970	--	255,000
O&M	--	--	--	--	--	--	--
Fixed Charges							
Private	--	12.67	13	12.67	13	--	12.7
Federal	--	5.58	--	5.58	--	--	5.6

---

[1] Capacity costs in dollars per kW. O&M costs in mills per kWh.
[2] In percent.
[3] In mills per kWh.
[4] Both capacity and O&M costs are in dollars per mile.

Table 7-3. OVERALL COST ESTIMATES
1975 Dollars

Generation	Construction ($/kW)	O&M (mills/kWh)
Coal (over 600 MW)	See regional breakdown	2.5
Nuclear (over 600 MW)	See regional breakdown	1.0
Peaking (large)		
Steam	$250	2.0
Diesel	160	10.0
Gas turbine		
Simple	150	1.3
Compound	240	1.5

Transmission	Construction ($/mile)	O&M ($/mile)
Alternating current (kV)		
345		
S/C	$110,000	$730
D/C	200,000	NA
500 S/C	230,000	926
765 S/C	325,000	866
Direct current (kV)		
±400	190,000	NA
±600	255,000	NA

Fixed Charges	Private	Federal
Generation	14.0%	7.4%
Transmission	12.7%	5.6%

Nuclear fuel cycle cost = 3.0 mills per kWh

NA = Not available

KEY
S/C = Single circuit
D/C = Double circuit

able 7-4. ESTIMATED REGIONAL GENERATION PLANT CONSTRUCTION COSTS
1975 Dollars

ational Electric Reliability Council Region	Coal ($/kW)	Nuclear ($/kW)
NPCC	$ 600	$604
MAAC	540	572
SERC	480	556
ECAR	540	540
MARCA	600	635
MAIN	580	635
SPP	520	556
ERCOT	520	NA
WSCC	500-540	540

A = Not available

Table 7-5. REGIONAL GENERATION PLANT CONSTRUCTION COSTS AND INDEXES

National Electric Reliability Council Region	Coal		Nuclear	
	$/kW in 1969	Index	$/kW in 1969	Index
NPCC	$ 150	125	$190	111.8
MAAC	135	112.5	180	105.9
SERC	120	100	175	102.9
ECAR	135	112.5	170	100
MARCA	150	125	200	117.6
MAIN	145	120.8	200	117.6
SPP	130	108.3	175	102.9
ERCOT	130	108.3	NA	NA
WSCC	125-135	104.2 to 112.5	170	100

NA = Not available

SOURCE: FPC P-38, *Hydroelectric Power Evaluation, Supplement No. 1,* 1969. Table 10.

As previously noted, there may be significant cost savings in placing generation plants in areas of the nation where construction costs are lowest. Indexes showing these cost factors were derived. Table 10 of the *FPC Hydro Power Evaluation, Supplement No. 1, 1968,* gives the costs of both nuclear- and coal-fired generation by Federal Power Commission power supply areas. A map of these Federal Power Commission power supply areas was overlaid with the one showing National Electric Reliability Council regions. Then, from table 10 for both nuclear- and coal-fired generation plants, the construction costs for each power supply area were noted on this map. The result was a map showing what the construction costs in dollars per kilowatt were for both coal and nuclear generation plants in each of the National Electric Reliability Council regions.

We found that within each NERC region there were one or more different construction dollar values. The mode of the dollar values in each region was chosen as the construction cost representive of the region. There are, thus, nine different construction cost figures for both coal and nuclear plants. These numbers were indexed, with 100 representing the lower value in each plant category. The indexes were applied to the values chosen in table 7-2 to derive regional costs for each NERC region as shown in table 7-4. Table 7-5 illustrates the development of these indexes.

EVALUATION OF COSTS AND BENEFITS

Approach and Limitations

Systematic and detailed determination of the specific nature of and probable amounts of costs and benefits that would result from a fully developed national grid is beyond the scope of this study. Much of what could evolve into a full national power grid already exists. We have, therefore, concentrated on certain aspects where identifiable benefits might result from deliberate activity not now contemplated.

In this quantitative analysis, we considered the benefits of making two regional interconnections that do not exist at this time. These interconnections are a transmission system from the WSCC region to the MARCA region and another, shorter, transmission system from the ERCOT region to the SPP region.

The *Report of the Western United States - Central United States Study of Transmission Interconnection* (WUS-CUS)[3] was made in 1973 to explore the possibility of strengthening interties between the western interconnected systems and the eastern interconnected systems. There are currently seven interconnections between the two regions. However, these interconnections are normally kept open because of problems with system stability. We have chosen to revise the 1973 study to see if significant changes have occurred that would warrant an in-depth study of specific alternatives for a substantially strengthened interregional transmission system.

Original Study

The WUS-CUS study evaluated a generalized east-west interconnection tying the West Coast to ". . . points on or in the vicinity of the Mississippi River . . .",[4] roughly 1,900 miles long. An interconnection of either ac or dc transmission lines was considered. An alternating current (ac) transmission interconnection would require at least two 765-kV interconnections to provide 1,200-MW firm-transfer capability and allow for unscheduled power flows up to 1,300 MW.

A single bipolar ±450-kV transmission line would be necessary for a direct current (dc) interconnection. "To approximately optimize the comparison to ac, limit line loss to 14% and avoid too great a disturbance to western systems if loss of a tower were to occur, the [dc] capacity compared was limited to 1,200 MW."[5] The economic evaluation weighed the benefits of accelerated interconnection against the costs and concluded that neither the ac nor the dc interconnection could be economically justified.

Capital costs, plus operation and maintenance costs, had an estimated present value of $1,547 million for ac interconnection or $387 million for dc interconnection. Neither estimate included the costs of stepdown transformers at the intermediate substations.

Benefits resulting from capture of load diversity within a season amounted to an equivalent of 2,400 MW of generating capacity valued at $342 million with an ac interconnection, or $310 million with a dc interconnection. Net annual savings of $4.6 million (ac) or $3.1 million (dc) would be possible, according to the study, through utilization of economy energy or transferring energy to minimize use of specific fuels. These annual savings amounted to $35 million for ac or $24 million for dc on a present-worth basis.

Total benefits calculated in the study amounted to $377 million for ac or $334 million for dc. Costs were greater than benefits by $1,170 million for ac and $53 million for dc in present-value terms.

Update

Our revisions in the updated version of the WUS-CUS study reflect the upward trend in prices since 1973, affecting costs of financing, construction, and fuels. The general assumptions made and methodology followed are the same as in the original study. The discount rate we used for present value analysis is 14 percent, compared to 13 percent in the original study, principally reflecting higher interest costs. The original and revised estimates of costs and benefits are shown on table 7-6 and 7-7 and are explained below.

Capital Costs. The 1973 WUS-CUS study estimated 1975 capital costs and escalated them 5 percent per year for 5 years to arrive at 1980 cost estimates. In our revision, the figures were deescalated at 5 percent for 5 years and subsequently reescalated over the 5 years at a higher rate. We forecast construction costs to increase at about 16 percent annually--significantly higher than the 5 percent predicted in 1973. This higher rate, based on 1975 actual costs, escalated the proposed capital costs about 60 percent. The costs are understated because, as in the original study, they do not include the cost of stepdown transformers at the intermediate substations.

Operation and Maintenance Costs. Since the original WUS-CUS study did not disclose how operations and maintenance costs of $900 and $700 per mile, respectively, for ac and dc interconnections were derived, we assumed that the same methodology was used as that used in figuring capital costs--estimates of 1975 costs escalated at 5 percent for 5 years. Again, to arrive at the revised per mile O&M costs, these figures were deflated at 5 percent per year for 5 years, then reescalated at 16 percent for 5 years.

Using $1,480 per mile of transmission line and 0.3 percent of the revised capital cost for terminal facilities,[6] we computed the yearly O&M cost of the ac facilities to be $6.9 million. This we capitalized at 14 percent for 30 years to arrive at $48 million as the present value of the total O&M costs of the ac interconnection. A similar method was used to calculate the $23 million present value of the O&M costs of the dc interconnection.

Thus, we estimate the total capitalized costs of an east-west intertie to be $2,542,000,000 for a 1980 in-service ac system and $624,000,000 for a dc system. These figures, as noted, do not include estimates for the cost of stepdown transformers at intermediate substations. See tables 7-6 and 7-7.

Load Diversity Savings. By comparing the combined northwest and southwest areas with the combined north-central and south-central areas, the original study estimated total coincident peak demand to be 2 percent less than the sum of the two noncoincident peak demands.[7] They assumed that the 2 percent, or 3,500 MW, would be a valid estimate of load diversity for the 1980's.

Recent forecasts by WSCC and MARCA indicate load diversity will run about 2.6 percent of coincident peak demand, 2,700 MW, in 1980. The WUS-CUS study reduced the estimated 3,500 MW available from load diversity to 2,400 MW to account for diversity being widely scattered.[8] Reducing the 2,700 MW by the same proportion leaves approximately 1,850 MW available in 1980. Both were reduced further to reflect line losses of 5 percent over ac lines and 14 percent over dc lines.

Diversity interchanges would likely result in forestalling installation of peaking capacity. Therefore, our calculations of savings are made using estimated costs of peaking capacity.[9] Peaking capacity now costs about $150 per kW. This was the value used in the original study for 1980. This was escalated at 12 percent annually for 5 years to arrive at the $264 per kW we used for the revised study. This value multiplied by 1,850-MW load diversity, after allowing for line losses, yields total capacity savings of $464,000,000 for an ac system or $422,000,000 for a dc system.

Economy Energy Savings. The original study estimated economy energy to be available 4,500 hours per year--15 hours per day 300 days per year.[10] Assuming that 1,200 MW were scheduled for half that time (2,250 hours), there would be net energy savings of 2.7 billion kWh before line losses of 5 percent and 14 percent for the ac and dc interconnections, respectively.[11] The 1973 study valued net energy savings at 2 mills per kWh and losses at 6 mills per kWh. We estimate the incremental costs of energy generation in these two regions will be about 7 mills per kWh for economy energy (mostly nuclear) and 17 mills per kWh for the higher cost energy offset (mostly coal). Therefore, the difference in costs, or the savings, would be 10 mills per kWh. We valued line losses at 7 mills per kWh, the assumed energy cost of the selling region.

The original study calculated the net savings by multiplying the gross MWh savings of 2.7 billion kWh by estimated savings of 2 mills and then subtracting 5 percent line loss of 0.135-billion kWh valued at 6 mills per kWh, effectively assigning a cost of 4 mills per kWh to the line loss. Our revision of the study valued the net energy savings at 10 mills per kWh and subtracted from that the line loss valued at 7 mills per kWh to arrive at a yearly savings of $24.7 million with an ac system and $20.6 million with a dc system. Capitalized at 14 percent, this yields a total savings of $173 million for an ac interconnection and $144 million for a dc interconnection. The results of these calculations are summarized in table 7-6.

Table 7-6. SUMMARY COMPARISON OF ESTIMATED SELECTED COSTS AND BENEFITS OF A WUS-CUS EHV TRANSMISSION INTERCONNECTION, 1973 AND 1975

	Original 1973 Study	Revised 1975 Study
	---Millions of Dollars--- (1980 In-Service Date)	
Alternating current:		
Costs	1,547	2,542
Benefits	377	637
Difference (cost)	1,170	1,905
Benefit/cost ratio	0.243/1	0.25/1
Direct current:		
Costs	387	624
Benefits	334	566
Difference (cost)	53	58
Benefit/cost ratio	0.863/1	0.91/1

In summary, our revision of the study reaches substantially the same conclusions as the original work: neither the ac nor the dc line can be justified clearly on tangible economic grounds alone. Costs of the ac intertie outweight benefits by a substantial amount. It must be emphasized that these estimates are preliminary and not all-inclusive. However, estimated costs of a dc intertie exceed benefits by only about 10 percent in our revision of the study. This benefit/cost ratio is less than the magnitude-of-estimating error normal for such order-of-magnitude estimates. Therefore, we conclude that a more detailed examination of this possible major interconnection is justified. When such study is undertaken, the area of examination should also consider alternatives to this intertie. For example, one task within the study should be to determine if there are intertie alternatives more beneficial than an east-west one. Strengthening existing north-south interties, both within MARCA and within WSCC, to accomplish diversity and economy interchanges, preempting an

Table 7-7. COMPARISON OF ESTIMATED SELECTED COSTS AND BENEFITS OF A WESTERN UNITED STATES - CENTRAL UNITED STATES EXTRA-HIGH-VOLTAGE TRANSMISSION INTERCONNECTION

	Original 1973 Study	Revised 1975 Study
	---------($000)	----------
CAPITAL COSTS		
AC Interconnection		
3,800 miles 765-kV line at $320,000/mile	$1,216,000	$2,001,000
Eight intermediate substations with three 765-kV circuit breakers @ $5,400,000/sub (excluding transformation)	43,000	71,000
Ten intermediate single-breaker substations @ $2,000,000 each	20,000	33,000
Four terminal substations with one 765-kV circuit breaker and two 1,200-MVA transformer @ $9,500,000/sub	38,000	63,000
Twenty 350-MVAR, 765-kV shunt reactors @$2,300,000 each (100% compensation)	46,000	76,000
Twenty 380-MVAR, 765-kV series capacitor banks @ $5,200,000 each (50% compensation rated 2,000 MVA)	104,000	171,000
Terminating transmission capacity @ $5/kW	48,000	79,000
Subtotal	$1,515,000	$2,494,000
DC Interconnection		
1,900 miles ±450-kV line @ $110,000/mile	$ 209,000	$ 344,000
Two 1,200-MW terminals @ $60/kW/terminal (includes all var requirements)	144,000	237,000
Terminating transmission capacity @ $5/kW	12,000	20,000
Subtotal	$ 365,000	$ 601,000
OPERATION AND MAINTENANCE		
AC Interconnection Program		
Using $900 per mile per year for 765-kV transmission lines and 0.3% of capital cost per year for terminal facilities, operation, and maintenance will be $4.2 million, annually.	$ 32,000[5]	$ 48,000[6]
DC Interconnection Program		
Using $700 per mile per year for ±450-kV DC transmission lines and 0.6% of capital cost per year for terminal facilities, operation, and maintenance will be $2.8 million annually.	22,000[5]	23,000[6]
TOTAL COST:		
AC Interconnection	$1,547,000	$2,542,000
DC Interconnection	$ 387,000	$ 624,000

	Original 1973 Study	Revised 1975 Study
	---------($000)	---------
LOAD DIVERSITY SAVINGS		
AC Interconnection		
2,280 MW at $150/kW	$342,000	
1,758 MW at $264/kW		$464,000
DC Interconnection		
2,064 MW @ $150/kW	310,000	
1,591 MW @ $264/kW		422,000
ECONOMY ENERGY SAVINGS		
AC Interconnection		
1,200 MW scheduled for 2,250 hrs/year less 5% line loss:		
Valued @ 2 mills/kWh[1]	35,000[2]	
Valued @ 10 mills/kWh[3]		173,000[4]
DC Interconnection		
1,200 MW scheduled for 2,250 hrs/year less 14% line loss:		
Valued @ 2 mills/kWh[1]	24,000[2]	
Valued @ 10 mills/kWh[3]		144,000[4]
TOTAL SAVINGS (BENEFITS):		
AC Interconnection	$377,000	$637,000
DC Interconnection	$334,000	$566,000

Note: Analysis based on assumed 1980 in-service data.

---

[1] Losses costed at 6 mills/kWh.

[2] Annual savings capitalized at 13%. (See WUS-CUS study.)

[3] Losses costed at 10 mills/kWh.

[4] Annual savings capitalized at 14%. (See table 7-8.)

[5] Annual cost capitalized at 13%. (See WNS-CUS Study.)

[6] Annual cost capitalized at 14%. (See table 7-8.)

Table 7-5. LEVELIZED ANNUAL REVENUE REQUIREMENTS FOR VARIOUS TYPES OF UTILITIES WSCC AND MARCA[1]

	Federal	Municipal or Public Power Districts	Cooperative	Investor Owned	Composite All Types Of Utilities
% of Total 1980 Capacity Installed	14	15	3	68	
Type of Financing & Proportion					
Bond	100	100	100	55	
Preferred Stock				10	
Equity				35	
Component of Revenue Requirement and Approximate % of Investment					
Bond	6.5	8.0	7.0	8	
Preferred				11	
Equity				13	
Total Return	6.5	8.0	7.0	10.00	9.15
Income Tax (Federal & State)				2.79	1.9
Depreciation Annuity[2]	1.16	.88	1.06	.75	.84
Insurance	.10	.10	.10	.10	.10
Total Revenue Requirement					11.99
Property Tax[3]					2.00
Total					13.99 Use 14.00

---

[1] The purpose of this table is to derive a composite revenue requirement for use in capitalizing costs and savings estimates.

[2] Elwood tables for real estate appraising and financing.

[3] Based on expectations considering areas of construction and the large size of development. This also includes any other payments made in lieu of taxes.

SOURCE: *Report of the Western United States-Central United States Study of Transmission Interconnection*, 1973; EBASCO Services, Inc. *Analysis of Public Utility Financing*. 1974.

east-west interchange, may yield more overall benefits than the proposed intertie by saving oil and gas rather than coal and nuclear resources.

The FPC's 1972 *Study of Proposed Interconnection Between Electric Reliability Council of Texas and Southwest Power Pool*,[12] examined briefly in chapter 5 of this report, determined that interconnection could possibly result in a 3-percent reduction of ERCOT reserves from 1975 to 1980. To arrive at this figure, reserve loads were determined for the ERCOT and SPP regions, first isolated and then interconnected. Although the study did not consider the cost of building the interconnection, it suggested that there was sufficient evidence of cost savings to justify detailed load flow and transient stability studies to further evaluate the feasibility of such an interconnection. Because of the magnitude of the estimated benefits of this interconnection, the recent changes in costs of capital, and growing concern over natural gas reserves and oil availability, we believe that incentive for doing comprehensive, detailed studies still exists.

OTHER ANALYSES

It is likely to be feasible at some future time to complete the national grid transmission system across the last remaining gaps. Also, specific extensions and reinforcements of existing facilities will deserve consideration. We expect all of these facilities to evolve from transmission plans now being implemented. Each line to be added to the system and each extension or reinforcement of existing facilities, when its need is identified, should be evaluated separately. It is desirable that each element of a national grid, over its expected life, be capable of producing benefits that will more than compensate for overall costs insofar as possible. In cases where a segment cannot support itself, it should make possible specific compensating benefits elsewhere.

A full analysis of the economics of a national grid is dependent on settlement of policy issues and specification of an identifiable entity to construct and operate a grid. Therefore, neither a discrete grid nor specific grid elements is considered in this study other than the WUS-CUS and the ERCOT-SPP interconnections discussed above. Further study will be needed to specify grid elements sufficient to allow detailed benefit/cost analysis.

An alternative approach to an evaluation of economic considerations related to a national grid is to look first at broad estimates of potential as possible savings that may be related directly or indirectly to a grid. These estimates may be used as a basis for estimating the amount of capital that could be used in alternate investments that would assist in achieving the assumed potential savings.

We found certain characteristics about the bulk power industry likely to have great influence on decisions about a national grid. The findings were to some extent contrary to what some perceive to be the benefits of an accelerated effort to construct a discrete national power grid system.

The analysis of load diversity in chapter 3 showed that on a national scale, after planned maintenance is accounted for, little uncaptured seasonal load diversity remains under current demand levels and patterns. Among the seven interconnected regional electric reliability councils of the Eastern United States, there is regular interchange of power amounting to 18,000 MW.[13] Similar exchanges of less magnitude regularly occur within the WSCC. This power, of course, cannot be used for any additional diversity exchange. Diversity resulting from time zone differences is even more elusive and cannot be given any economic value. It is of no value as a basis for system planning.

The analysis of nonsimultaneous emergency transfer capability in chapter 5 showed that there is more capability currently installed between regional reliability councils than there is usable seasonal load diversity within the reliability councils. Exceptions to this general finding are the lack of transfer capability between the WSCC and MARCA and between ERCOT and SPP. There are also a few isolated locations between the interconnected reliability councils where capability is below usable load diversity after maintenance is accounted for.

Excepting an ERCOT-SPP interconnection, and possibly a WSCC-MARCA dc interconnection, it appears that all major interconnections that are economically and technically feasible to operate are now being used to the fullest level currently economically attainable. New interconnections are being planned and constructed as needs and feasibility evolve.

Variable and rapidly increasing fuel costs, uncertainties of fuel availability, and lack of identifiable load diversity all currently constrain acceleration of development of a national grid and agreements to interchange power. A remaining potential for significantly reducing costs in the bulk electric power industry is the reduction of operating reserves, as discussed in chapter 4. We also raised a question about the reliability or loss-of-load objectives of the electric power industry. These considerations for possible reduction of reserves are not direct requirements for or results of a national grid. They open the way, however, for an evaluation based on a possible indirect relationship.

Reduction of Reserves

We conducted several analyses to determine the present values and benefits to electric consumers of possible savings from reducing reserves to selected levels over a 10-year period, starting with the present. The first two analyses are based on calculations shown in chapter 4. Table 4-5 shows how much reducing operating reserves by 1 percentage point would save the nation in capital resources. The estimated total present value over 10 years of an immediate reduction in reserves by 1 percentage point amounted to $3.16 billion. When nuclear generation costs are included, the value increases about 2 percent. In terms of annual worth, based on levelized revenue requirements of 14 percent per year,[14] the annual savings would be $442 million. This amounts to $0.0002599 per kWh based on total 1974 sales of 1,700,769 million kWh in the United States.[15]

If these savings were distributed to all consumers in proportion to annual kWh usage, all residential customers would be benefited by a total of $144 million based on total residential usage of 554,960 million kWh. The average annual residential usage was 7,907 kWh in 1974. Therefore, under an assumed distribution of the benefits of reduced reserves as noted above, the average residential customer or average household would receive an annual electric bill reduction of $2.06. If the entire benefits of a 1-percentage-point reduction in operating reserves were distributed among the residential consumers, the annual average amount received would be $0.0007965 per kWh or $6.30 per average residential consumer.

Table 4-6 of chapter 4 shows the savings in capital resources that would result if operating reserves were reduced all at once in 1976 to a level of 15 percent of projected peak summer demand for the whole industry, allowing for the changes in reserves that are already planned. We calculated the present value over 10 years of these net savings to be $20.1 billion. Following the same analysis as used above, the 14-percent annual levelized revenue requirements would provide an annual worth of $2.81 billion. This amounts to $0.0016522 per kWh based on total 1974 sales of 1,700,769 million kWh in the United States.

If these savings were distributed to all customers in proportion to annual kWh usage, all residential customers would be benefited annually by a total of $916.9 million, based on the total 1974 residential usage of 554,960 million kWh. Under the assumption used above of distribution of the benefits on a basis of annual kWh usage, the average household would receive an annual electric bill reduction of $13.06. If all of the annual benefits were distributed only to residential customers, the average annual residential bill would be reduced by $40.04, or 18 percent of the average 1974 bill of $223.77.[16]

For additional analysis, we assumed that perhaps some leeway in reserves would be desirable. See the analysis of reserve determination in chapter 4. We therefore chose 17.5 percent of annual peak demand as the target for operating reserves. It would be more operationally realistic to reduce the reserves from the 1975 level gradually over the 10 years to 1984. As in the previous analysis, we used net savings--savings from reducing reserves below the level of that already planned. We further decided that it would be informative to perform the analysis on a regional reliability council basis. This analysis is presented in tables 7-9 and 7-10.

The analysis shows that the achievement of reserves of 17.5 percent over the 10 years results in a total savings of $20.44 billion. The planned reduction of reserves was to be $11.06 billion; the net savings, therefore, were estimated to be $9.38 billion. Allowing for reserve changes already planned, it should be noted some regional reliability councils show negative benefit from the achievement of a reserves level of 17.5 percent of annual peak demand. That is, some are now planning to have reserves below the 17.5-percent level at sometime during the period.

Total capital savings for the nation would have an annual value of $1.313 billion. This amounts to $0.000772 per kWh based on the total kWh used in 1974. The residential customers' share of these annual savings would amount to a total of $428.5 million or $6.10 per customer. If the entire benefits from reduction of reserves to 17.5 percent of peak demand over 10 years were distributed only to the residential customer segment, each household would realize a reduction in annual cost of electric energy of $18.71.

Another way of measuring the effect of the $1.313 billion annual saving on electric rates is that this amount would represent a 3.4-percent reduction in the $39 billion annual revenue of electric utilities in the United States in 1974. However, in actuality this saving would probably have to be reduced in some amount, indeterminant within the scope of this study, to allow for any costs of transmission lines or reduced reliability associated with the reduction in reserves.

[illegible] ESTIMATED SAVINGS FROM ACCELERATED REDUCTIONS IN OPERATING RESERVES TO 17.5% FROM 1975-1984, BY REGIONAL ELECTRIC RELIABILITY COUNCIL

Region	1975	1976	1977	1978	1979	1980	1981	1982	[illegible]	1984	Present Value ($[illegible])
ECAR											
1 Total installed capacity	[illegible]	79,665	83,206	86,650	91,239	96,544	[illegible]	[illegible]	[illegible]	116,882	
2 Projected general reserves (%)	29.21	28.04	26.87	25.70	24.53	23.36	22.19	[illegible]	[illegible]	18.68	
3 % savings/year (10% x 11.7[illegible])	1.17	1.17	1.17	1.17	1.17	1.17	1.17	[illegible]	[illegible]	1.17	
4 Adjusted reserves (L. 2 - L. 3)	28.04	26.87	25.70	24.53	23.36	22.19	21.02	[illegible]	[illegible]	17.51	
5 MW savings (L. 1 x L. 3)	861.82	932.08	[illegible]	1,013.81	[illegible]	1,129.56	[illegible]	[illegible]	[illegible]	1,367.52	
6 $ savings, $540/kW ($000)	465,383	[illegible]	525,696	576,455	576,448	[illegible]	644,436	[illegible]	[illegible]	[illegible]	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	[illegible]
ERCOT											
1 Total installed capacity	32,873	34,226	36,919	39,652	42,148	46,505	[illegible]	54,749	[illegible]	59,288	
2 Projected general reserves (%)	30.07	28.81	27.55	26.29	[illegible]	23.77	22.51	[illegible]	19.99	18.73	
3 % savings/year (10% x 12.[illegible])	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	
4 Adjusted reserves (L. 2 - L. 3)	28.81	27.55	26.29	25.03	23.77	22.51	[illegible]	19.99	18.73	17.47	
5 MW savings (L. 1 x L. 3)	414.20	431.25	465.18	499.62	531.06	585.96	634.66	689.84	719.06	[illegible]	
6 $ savings, $52[illegible]/kW ($000)	[illegible]	[illegible]	241,893	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	386,455	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	[illegible]
MAAC											
1 Total installed capacity	[illegible]	[illegible]	45,153	46,478	48,153	49,839	[illegible]	[illegible]	[illegible]	[illegible]	
2 Projected general reserves (%)	30.79	29.46	28.13	26.80	25.47	24.14	22.81	21.48	[illegible]	18.82	
3 % savings/year (10% x 13.29)	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	
4 Adjusted reserves (L. 2 - L. 3)	29.46	28.13	26.80	25.47	24.14	22.81	21.48	[illegible]	18.82	17.49	
5 MW savings (L. 1 x L. 3)	555.41	561.82	600.53	618.16	[illegible]	662.81	[illegible]	[illegible]	[illegible]	834.6	
6 $ savings, $557/kW ($000)	309,362	312,934	334,495	344,315	[illegible]	369,185	[illegible]	[illegible]	[illegible]	464,911	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	[illegible]
MAIN											
1 Total installed capacity	36,194	38,537	40,370	43,636	47,513	49,668	53,228	[illegible]	61,065	66,425	
2 Projected general reserves (%)	13.26	13.68	14.11	14.53	14.96	15.38	15.80	16.23	16.65	17.08	
3 % savings/year (10% x 4.24)	(.424)	(.424)	(.424)	(.424)	(.424)	(.424)	(.424)	(.424)	(.424)	.424	
4 Adjusted reserves (L. 2 - L. 3)	13.68	14.11	14.53	14.96	15.38	15.80	16.23	16.65	[illegible]	[illegible]	
5 MW savings (L. 1 x L. 3)	(153.46)	(163.40)	(171.17)	[illegible]	(201.46)	(210.59)	[illegible]	(242.58)	(258.92)	(281.64)	
6 $ savings, $599/kW ($000)	(91,923)	(97,877)	(102,531)	(110,827)	(120,675)	(126,143)	(135,188)	[illegible]	[illegible]	(168,702)	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	[illegible]
MARCA											
1 Total installed capacity	18,663	20,168	21,525	22,148	24,585	25,622	26,654	27,254	28,153	28,153	
2 Projected general reserves (%)	30.66	29.34	28.04	26.70	25.38	24.06	22.74	21.42	[illegible]	18.78	
3 % savings/year (10% x 13.16)	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	
4 Adjusted reserves (L. 2 - L. 3)	29.34	28.04	26.70	25.38	24.06	22.74	21.42	[illegible]	18.78	17.46	
5 MW savings (L. 1 x L. 3)	246.35	266.22	284.13	292.35	324.52	338.21	351.83	359.75	371.62	371.62	
6 $ savings, $608/kW ($000)	149,784	161,862	172,751	177,749	197,308	205,632	213,913	218,728	225,945	225,945	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	1,181,780
NPCC											
1 Total installed capacity	69,386	74,684	77,864	80,882	83,936	89,887	[illegible]	99,583	[illegible]	106,383	
2 Projected general reserves (%)	42.88	40.34	37.80	35.26	32.72	30.18	27.64	[illegible]	22.56	20.02	
3 % savings/year (10% x 25.38)	2.54	2.54	2.54	2.54	2.54	2.54	2.54	[illegible]	2.54	2.54	
4 Adjusted reserves (L. 2 - L. 3)	40.34	37.80	35.26	32.72	30.18	[illegible]	[illegible]	22.56	[illegible]	[illegible]	
5 MW savings (L. 1 x L. 3)	[illegible]	1,896.97	1,977.75	[illegible]	2,131.97	2,283.13	[illegible]	2,529.41	[illegible]	[illegible]	
6 $ savings, $603/kW ($000)	[illegible]	1,143,873	1,192,583	1,238,803	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1,629,384	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	[illegible]
SERC											
1 Total installed capacity	17,623	19,643	22,061	23,510	25,030	[illegible]	26,987	28,347	[illegible]	31,804	
2 Projected general reserves (%)	23.42	22.83	22.24	21.64	[illegible]	[illegible]	[illegible]	19.28	18.68	[illegible]	
3 % savings/year (10% x 5.92)	.592	.592	.592	[illegible]	.592	.592	.592	[illegible]	.592	.592	
4 Adjusted reserves (L. 2 - L. 3)	22.83	22.24	21.64	21.05	20.46	[illegible]	19.28	18.68	[illegible]	[illegible]	
5 MW savings (L. 1 x L. 3)	104.33	116.29	130.60	139.18	148.18	[illegible]	159.76	[illegible]	[illegible]	188.28	
6 $ savings, $539/kW ($000)	56,234	62,680	70,393	[illegible]	79,869	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	489,651
SPP											
1 Total installed capacity	41,309	43,317	45,233	49,074	52,199	56,940	58,409	63,336	65,411	67,685	
2 Projected general reserves (%)	18.93	18.79	18.64	18.50	18.36	18.22	[illegible]	[illegible]	17.79	[illegible]	
3 % savings/year (10% x 1.43)	.143	.143	.143	.143	.143	.143	.143	.143	.143	.143	
4 Adjusted reserves (L. 2 - L. 3)	18.79	18.64	18.50	18.36	18.22	[illegible]	17.93	[illegible]	[illegible]	17.50	
5 MW savings (L. 1 x L. 3)	59.07	61.94	64.68	70.18	74.64	81.42	[illegible]	90.57	93.54	96.79	
6 $ savings, $530/kW ($000)	31,307	32,828	34,280	37,195	39,559	[illegible]	44,266	[illegible]	49,516	51,299	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	[illegible]
WSCC											
1 Total installed capacity	89,073	96,414	102,807	108,317	114,988	122,279	[illegible]	139,893	[illegible]	155,993	
2 Projected general reserves (%)	26.55	25.64	24.74	24.74	22.93	22.02	21.12	20.22	19.31	18.40	
3 % savings/year (10% x 9.05)	.905	.905	.905	.905	.905	.905	[illegible]	.905	[illegible]	.905	
4 Adjusted reserves (L. 2 - L. 3)	25.64	24.74	23.84	22.93	22.02	21.12	20.22	19.31	18.40	[illegible]	
5 MW savings (L. 1 x L. 3)	806.11	872.55	930.40	980.27	1,040.64	1,106.62	[illegible]	1,266.03	1,332.79	1,411.74	
6 $ savings, $528/kW ($000)	425,626	460,706	491,251	517,583	549,458	584,295	619,962	668,464	703,713	745,399	
7 Present value of savings	--	--	--	--	--	--	--	--	--	--	3,458,684
TOTAL											20,440,774

SOURCE: NERC, *Review of Overall Reliability and Adequacy of the North American Bulk Power Systems*, July 1975, Appendix B; and table 11.

[illegible] RESULTS AND ESTIMATED [illegible] FROM PROJECTED
GENERATING RESERVES BY REGIONAL ELECTRIC RELIABILITY COUNCIL 1975-1984

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	Present Value $000
[illegible]											
1 Total installed capacity	[illegible]	74,684	[illegible],864	80,882	83,936	89,887	92,[illegible]	99,583	[illegible]	106,383	
2 Projected general reserves	[illegible]	[illegible]	[illegible].15	31.49	30.55	2[illegible].61	29.47	30.17	30.16	[illegible]	
3 % savings/year		[illegible].48	3.[illegible]5	5.86	[illegible]	[illegible]	[illegible]1.84	[illegible]	[illegible].59	[illegible]	
4 Mw savings		[illegible]	[illegible]	4,739.69	[illegible]	[illegible],624.[illegible]	[illegible]1,695.14	([illegible]697.[illegible])	[illegible]	[illegible],18[illegible].85	
5 $ savings ([illegible]/kW)		[illegible]	[illegible]	[illegible]	[illegible]	[illegible],694	[illegible]	(42[illegible],339)	(363,187)	[illegible]	
6 Present value of savings, 40 years, 9.[illegible]		--	--	--	--	--	--	--	--	--	4,85[illegible]
[illegible]											
1 Total installed capacity	1[illegible],623	19,641	22,061	[illegible]	[illegible],0[illegible]	25,475	26,987	28,347	[illegible]9,82[illegible]	31,804	
2 Projected general reserves	[illegible]4.	[illegible]3.57	21.38	[illegible]	19.16	16.46	18.[illegible]	18.64	17.07	1[illegible].08	
3 % savings/year		([illegible].15)	2.19	[illegible]	1.51	2.7[illegible]	([illegible].9[illegible])	[illegible]	1.57	[illegible]	
4 Mw savings		[illegible]9.46	483.14	166.[illegible]2	[illegible].95	68[illegible].82	([illegible]5.45)	76.54	468.[illegible]	(3.18)	
5 $ savings ([illegible]3[illegible]/kW)		([illegible]5,879)	26[illegible],4[illegible]	89,9[illegible]	2[illegible]	3[illegible],735	([illegible]77,828)	41,[illegible]	25[illegible],4[illegible]	([illegible],714)	
6 Present value of savings, 40 years, 9.[illegible]		--	--	--	--	--	--	--	--	--	535,8[illegible]
[illegible]											
1 Total installed capacity	41,3[illegible]9	43,317	45,233	49,[illegible]4	52,199	56,94[illegible]	58,409	63,3[illegible]	[illegible],411	6[illegible],885	
2 Projected general reserves	18.93	15.73	11.39	12.84	12.[illegible]8	14.78	12.56	16.4[illegible]	16.24	15.[illegible]	
3 % savings/year		3.[illegible]	4.34	(1.4[illegible])	[illegible].56	[illegible]2.5	2.[illegible]	([illegible]3.84)	.18	1.[illegible]3	
4 Mw savings		1,386.14	[illegible],963.11	(711.5[illegible])	[illegible]292.31	1,423.50	1,296.68	(2,432.1[illegible])	[illegible]4.66	[illegible]64.84	
5 $ savings ([illegible]53[illegible]/kW)		734,654	1,040,448	(377,1[illegible])	154,924	([illegible]754,[illegible]55)	687,[illegible]4[illegible]	([illegible]289,[illegible]1[illegible])	[illegible],4[illegible]	[illegible]361	
6 Present value of savings, 40 years, 9.[illegible]		--	--	--	--	--	--	--	--	--	[illegible]3
[illegible]											
1 Total installed capacity	[illegible]9,[illegible]3	96,414	[illegible]	[illegible]8,31[illegible]	[illegible]14,988	122,279	129,743	139,893	14[illegible],27[illegible]	155,991	
2 Projected general reserves	26.55	28.25	28.15	28.48	[illegible].37	29.[illegible]	29.1[illegible]	27.62	31.02	31.86	
3 % savings/year		(1.7[illegible])	1[illegible]	(.33)	1.[illegible]	([illegible].63)	.17	1.55	(3.4[illegible])	[illegible].84	
4 Mw savings		(1,639.[illegible]4)	1[illegible]2.81	([illegible]4[illegible])	1,[illegible]76.37	(1,993.15)	([illegible]56)	[illegible],168.34	([illegible]18)	(1,[illegible]34)	
5 $ savings ([illegible]8/kW)		(865,413)	54,284	(188,734)	673,923	(1,[illegible]52,383)	(116,4[illegible])	1,144,884	([illegible],64[illegible])	(691,86[illegible])	
6 Present value of savings, 40 years, 9.[illegible]		--	--	--	--	--	--	--	--	--	(1,949,211)
[illegible]											
1 Total installed capacity	[illegible]3,66[illegible]	79,665	83,206	86,650	91,239	96,544	1[illegible]2,[illegible]	106,334	109,987	116,882	
2 Projected general reserves	29.21	29.18	25.7[illegible]	22.64	21.46	2[illegible].99	20.33	18.3[illegible]	15.53	15.96	
3 % savings/year		[illegible]	3.48	3.06	1.18	.47	.66	2.[illegible]	2.77	(.43)	
4 Mw savings		23.9[illegible]	[illegible],895.[illegible]7	2,651.49	1,[illegible]76.62	453.76	673.2[illegible]	2,158.58	3,[illegible]46.64	(5[illegible]2.59)	
5 $ savings ([illegible]4/kW)		[illegible]2,906	[illegible]563,607	[illegible],431,5[illegible]5	[illegible]81,[illegible]7	24[illegible],[illegible]29	363,528	([illegible]165,63[illegible])	1,64[illegible],186	(2[illegible]1,400)	
6 Present value of savings, 40 years, 9.[illegible]		--	--	--	--	--	--	--	--	--	4,083,[illegible]30
ERCOT											
1 Total installed capacity	32,873	34,226	36,919	39,652	42,148	46,505	50,370	54,749	5[illegible],[illegible]68	59,[illegible]88	
2 Projected general reserves	30.0[illegible]	24.22	22.05	21.45	19.33	2[illegible].[illegible]2	22.9[illegible]	[illegible]4.6[illegible]	21.49	[illegible].93	
3 % savings/year		5.85	1.57	1.20	2.2[illegible]	[illegible]2.69	(.97)	(1.6[illegible])	3.12	3.56	
4 Mw savings		2,002.22	579.63	475.82	935.69	1,25[illegible].98	(488.59)	(886.93)	1,78[illegible]	2,[illegible].65	
5 $ savings ($52[illegible]/kW)		1,041,155	301,407	247,426	486,557	(65[illegible],51[illegible])	([illegible]54,06[illegible])	(461,204)	92[illegible],87[illegible]	[illegible]97,538	
6 Present value of savings, 40 years, 9.[illegible]		--	--	--	--	--	--	--	--	--	[illegible]1,69[illegible]
MAAC											
1 Total installed capacity	41,760	42,242	45,1[illegible]3	46,478	48,153	49,839	53,341	58,47[illegible]	[illegible]9,557	62,[illegible]5[illegible]	
2 Projected general reserves	30.79	25.46	26.69	23.[illegible]5	[illegible]1.26	19.29	[illegible]1.48	26.9[illegible]	23.[illegible]3	[illegible]3.90	
3 % savings/year		5.33	(1.23)	3.44	1.99	1.97	(2.[illegible]9)	([illegible]5.4[illegible])	3.67	[illegible].6[illegible]	
4 Mw savings		2,[illegible]51.50	(555.38)	1,598.84	958.24	981.83	1,168.[illegible]	(3,169.45[illegible])	[illegible],185.[illegible]4	[illegible]4[illegible]	
5 $ savings ($5[illegible]/kW)		1,[illegible]45,[illegible]85	(309,347)	890,554	533,74[illegible]	546,879	(65[illegible],6[illegible])	(1,765,384)	(1,717,4[illegible]7)	[illegible]	
6 Present value of savings, 40 years, 9.[illegible]%		--	--	--	--	--	--	--	--	--	1,[illegible],6[illegible]
MAIN											
1 Total installed capacity	36,194	38,537	40,370	43,636	47,51[illegible]	49,668	5[illegible],[illegible]28	5[illegible],213	61,06[illegible]	66,4[illegible]	
2 Projected general reserves	13.26	13.28	9.52	10.89	13.34	11.24	1[illegible].14	13.44	11.[illegible]1	16.43	
3 % savings/year		([illegible]2)	3.76	(1.37)	(2.45)	2.10	[illegible].96	[illegible]1.3	([illegible])	(2.[illegible])	
4 Mw savings		([illegible]7.71)	1,5[illegible]7.91	(597.81)	([illegible]164.[illegible])	1,041.01	(479.[illegible])	([illegible]743.[illegible])	(128.[illegible]4)	1,806.76	
5 $ savings ($[illegible]99/kW)		4,618	909,228	(358,088)	(697,[illegible]78)	624,775	(286,951)	(445,519)	(76,916)	(1,[illegible]82,[illegible]49)	
6 Present value of savings, 40 years, 9.[illegible]%		--	--	--	--	--	--	--	--	--	(4[illegible]9,118)
MARCA											
1 Total installed capacity	18,663	20,168	21,525	22,148	24,585	25,6[illegible]2	[illegible]6,6[illegible]4	27,2[illegible]4	28,153	28,153	
2 Projected general reserves	30.66	31.06	29.63	25.14	30.[illegible]2	32.13	3[illegible].86	30.5[illegible]	2[illegible].24	2[illegible].19	
3 % savings/year		([illegible]4[illegible])	1.4[illegible]	4.49	(5.58)	(1.41)	1.2[illegible]	.34	3.28	.05	
4 Mw savings		80.6[illegible]	307.81	994.45	1,[illegible]1.84	36[illegible].[illegible]7	338.[illegible]	92.66	9[illegible]3.42	14.[illegible]	
5 $ savings ($608/kW)		(49,[illegible]47[illegible])	187,[illegible]48	6[illegible]4,626	(834,[illegible]79)	([illegible]219,6[illegible]2)	[illegible].814	56,3[illegible]	[illegible]1,4[illegible]	8,561	
6 Present value of savings, 40 years, 9.[illegible]%		--	--	--	--	--	--	--	--	--	[illegible]
TOTAL											11,[illegible]

SOURCE: NERC, *Review of Overall Reliability and Adequacy of the North American Bulk Power Systems*, July 1975, Appendix B, and table 7-[illegible]1

Table 7-11. WEIGHTED AVERAGE COAL/NUCLEAR GENERATION 1984 BY RELIABILITY COUNCIL REGION

	(1) % Nuclear Generation 1984	(2) $/kW Nuclear	(3) Weighted Cost, Nuclear (1) x (2)	(4) % Coal Generation 1984	(5) $/kW Coal	(6) Weighted Cost, Coal (4) x (5)	(7) Weighted Average Coal/Nuclear Generation $/kW
ECAR	13.3	540	71.8	86.7	540	468.2	540
ERCOT	30.7	No Data	--	69.3	520	364.5	520[1]
MAAC	51.7	572	295.7	48.3	540	260.8	557
MAIN	34.7	635	220.3	65.3	580	378.7	599
MARCA	22.9	635	145	77.1	600	462.6	608
NPCC	76.7	604	463.3	23.3	600	139.8	603
SERC	42.5	556	263.3	57.5	480	276	539
SPP	29.1	556	161.8	70.9	520	368.7	530
WSCC	39.2	520	211.7	60.8	520[2]	316	528

---

[1] Assumed all coal generation because of lack of nuclear data.

[2] Average of $500 to $540, see table 7-4.

SOURCE: Appendix B, NERC *Review of Overall Reliability and Adequacy of the North American Bulk Power Systems* (5th Annual Review), July 1975; and table 7-4.

The results of these three analyses are summarized in table 7-12.

Table 7-12. SAVINGS RESULTING FROM REDUCING OPERATING RESERVES BY SELECTED AMOUNTS

	Reserve Reduction		
	by 1% Point	to 15%	to 17.5%
Total present value of savings ($ millions)	3,158	20,071	9,380
Annual savings ($ millions)	442	2,810	1,313
Savings per kWh of total annual usage	$0.0002599	$0.0016522	$0.000772
Average annual residential customer savings based on total kWh usage	$2.06	$13.06	$6.10
Average annual residential customer savings if entire savings accrue to residential customers	$6.30	$40.04	$18.71

It must be emphasized again that a reduction in operating reserves would not necessarily be an outgrowth of building a national grid. Some reductions in reserves may be facilitated by a grid, but without extensive, indepth research this possibility cannot be quantified. Nevertheless, capital savings of $9.4 billion from reducing reserves to 17.5 percent raises the possibility of using the saved capital for extending and strengthening national and subnational interconnections. However, the possibility requires decisions about changing present standards of service reliability.

Other potential savings, such as those from economies of scale made possible through interconnection and interchange, are attractive, a national grid notwithstanding. We expect that they will be gradually achieved and the attendant required transmission facilities will be built as demand conditions and other influencing factors occur. Quantification must await specification of a grid and a determination of opportunities for changes in scale of system operations. Nevertheless, these potential economies may be promising, particularly considering currently installed generation and transmission mixes from system to system throughout the industry. They should be directly assessed in more detailed studies.

The potential savings by interconnecting hydroelectric systems with nonhydroelectric systems are now rapidly being achieved, particularly between the Pacific Northwest and the Pacific Southwest. At least one more Pacific Northwest-Pacific Southwest interconnection line is being planned, as shown in figure 5-1. Benefits are being achieved from international interconnections between Canadian hydroelectric systems and the U.S. Eastern interconnected systems. Additional interconnections between midwestern U.S. utilities and Manitoba are being studied. We believe that most available advantages from integration of hydro and thermal systems are being achieved currently. Perhaps others will be possible if significant additional hydroelectric sites are developed.

Fuel Oil and Natural Gas Savings

Conservation of domestic natural gas reserves and the diminution of petroleum imports are potential significant political and economic ramifications of a national power grid backed up by coal and nuclear generation. Consequently, we have estimated potential savings of fuel oil or natural gas for each 1,000-MW coal or nuclear electric generating plant operated instead of a plant using oil or natural gas fuel. These savings are shown in table 7-13.

Table 7-13. PETROLEUM AND NATURAL GAS SAVINGS

Saving of fuel oil and natural gas per year for each 1,000-MW coal or nuclear plant installed, instead of an oil- or gas-fueled plant

Plant Factor[1] (%)	Oil Saved (bbl$\times 10^6$)[2,3]	Natural Gas Saved (MCF$\times 10^6$)[2,3]
75	10.950	65.700
70	10.220	61.320
65	9.490	56.940
60	8.953	52.560
55	8.030	48.180

---

[1] Defined as the plant's (or unit's) continuous power production rating divided into the average power produced that year.

[2] Oil energy content: 6×10^6 Btu/bbl; gas energy content: 1×10^6 Btu/MCF.

[3] Assume heat rate of 10,000 Btu/kWh for oil- or gas-fired plant.

A single 1,000-MW coal or nuclear plant at 70-percent load factor would save the equivalent of about 10.2 million barrels of oil per year or 61.3 million mcf of natural gas per year.

CONCLUSIONS

A WUS-CUS alternating current interconnection still does not offer ample economic benefits to justify detailed study and allocation of capital resources for its development. As economic conditions change the value of electric energy relative to construction costs, and if large generation resources are developed in the western coalfields, the ac interconnection should again be studied. However, our updated study shows that changed conditions have improved the relative benefits of a direct current interconnection, and a more detailed study of such an intertie might prove fruitful.

The proposed ERCOT-SPP interconnection now, as in 1972, presents an ample basis for further study, particularly in light of much higher costs of capital, substantial changes in the relative prices, and availability of fuels for generating electricity, national emphasis on the reduction of consumption of petroleum resources, and widespread efforts to improve system load factors.

Reducing operating reserves is an area of the bulk power industry that offers significant potential for savings. Present value of savings of about $9.14 billion could be attained if generation reserves were reduced gradually over a 10-year period to an average of 17.5 percent. This saved capital could be used in many ways--reducing annual electric bills by small amounts, probably about 3 percent, or reinforcing and extending the national grid. At a cost of about $325,000 per mile, the $9.4 billion net savings could finance about 26,000 miles of 765-kV ac, single-circuit lines and associated substations, switching stations, and line compensation and control equipment, provided it were decided that the savings would best be used in this manner. However, this reduction of reserves would not necessarily be an outgrowth of building a national grid. It is more directly related to reliability standards.

Other potential savings assumed by some to have merit *a priori* did not prove in our research to offer significant possibilities for influencing the development of the national grid. This is particularly true of load diversity. It was once thought by many to offer ample motivation to establish interregional interconnections. We conclude from our analyses that much of the potential savings from load diversity disappeared as the nation went from an annual winter peak to an annual summer peak between 1964 and 1970. This potential may again evolve if patterns of energy usage change so that electricity becomes more attractive for winter heating in the northern tiers of the United States; however, there is no clear evidence now of this happening.

Potential economies of scale were not measured because of the elusive nature of these values without detailed specification of the system or systems to be considered. Also, the limitations of current technology indicate that larger, acceptably reliable generators are not likely to be available in the near future. Similarly, no effort was made to estimate the potential savings of increasing amounts of shared planned maintenance, nor of possible benefits that may be derived from further interconnecting hydro systems with nonhydro systems, except for the already-mentioned analysis of West Coast-Midwest interconnection. All of these areas may offer opportunities for reducing costs of electric energy. Once public policy concerning a national grid is addressed, each of these major areas must be thoroughly studied in the context of individual utility-national grid interface.

OTHER ECONOMIC FACTORS

Economic analysis based on hypothetical or unspecified entities usually results in understatement of both costs and benefits. Many costs and benefits possible in building a national grid or simply reducing reserves could not be assessed. For example, what benefit is gained from substituting hydro-generated energy for energy from oil-fired generators? We can say that the benefit has some relationship to the long-term, relative availability of each energy source. To correct this apparent problem, the government (especially the FEA) has attempted to alter existing patterns of fuel usage through regulation. A determination of the long-term economic importance of displacing oil and gas generation with hydro and coal generation would allow the value of interconnections to be more completely assessed.

In an "ideal" economy, the relative market prices of competing energy sources would account for their relative long-term scarcity. However, actual prices are based on short-run production costs; thus, oil, compared to the ideal, is probably less expensive (relative to hydro) than it should be. These "improper" relative prices lead to inefficient allocation of fuels and other basic energy resources.[17] Thus, of great importance to the nation in long-run supply-demand relationships in the energy sector is the need to encourage the pricing of individual energy sources relative to all other energy sources.

An important consideration for any electric utility is how various management decisions will affect customers. If savings due to interregional interconnection are significant and dependable, it is conceivable that electric rates could be reduced or at least not increased as rapidly as with no interconnections. This would especially be true of relatively high-cost systems interconnected with low-cost systems, provided the systems were able to exchange economy energy from load diversities.

OTHER CONSIDERATIONS

Decisions to build or not to build interconnections may not be made entirely on economic grounds. Two important noneconomic factors may be important decision criteria. These are treated in some detail elsewhere in this report, but also should be considered in connection with economic factors.

First are institutional considerations. These include: the actions of regulatory agencies with regard to interconnections, political attitudes, and public acceptance. Regulators can review plans for a proposed interconnection or suggest--even require in certain instances--that specific interties be built. Ideally, regulation would ensure that economic factors are fully accounted for. However, many decision variables are subject to interpretation under constraints of personal value judgments. Furthermore, noneconomic factors often enter into consideration.[18] Political influence can affect decisions of any kind in such a manner that economic goals are not always met. For instance, the ERCOT utilities may have chosen to remain isolated from those in neighboring states in order to avoid FPC regulation. If true, this would appear to be an issue not to be settled on economic grounds alone.

Public acceptance or rejection of proposed economic developments has become a powerful influence on many aspects of life in the U.S. Therefore, many technically feasible developments in the electric power industry will be determined in the final analysis by whether they are acceptable to the general public and not whether they can be economically justified.

Another major area of noneconomic consideration involves technical aspects.[19] There are many unknowns concerning the impact of interconnection on the operating stability of the utilities involved. The reliability of substations and transmission lines is often of as much concern as that of generation facilities. Uncontrollable power flows occur between interconnected areas and present difficult operating problems. These and other technical concerns make utilities wary of planning extensive interconnections over long distances without being solidly anchored to generation resources near their load areas.

■ FOOTNOTES TO CHAPTER 7

1 See chapter 4.

2 Nuclear Regulatory Commission. 1974. *The Nuclear Industry - 1974*, WASH 1174-74. Pages 18 through 21 and tables 1-3 and 1-4 were major sources of data used for this chapter.

Investment savings from reduced forced-outage rates. This is a two-page section that appeared in the FEA. March 1975. A report on improving the productivity of powerplants, on pages 73 and 74. Figure C-5 on page 73 of that report is the source of data used.

Federal Power Commission. *The 1970 National Power Survey, part 1*. The major chapters from which data were obtained are chapters 6, 8, 13, and 19.

The energy and generation scene: dreams, realities, and the future. This is a report by Robert G. Sheehan of Seattle City Light, presented at the Washington State University Thermal Power Conference on 4 October 1973. Figure 1 on page 3 of this paper was the primary source of data used.

FPC P-35, *Hydroelectric Power Evaluation, 1968*. Pages 51, 73, and 76 were the major sources of data from this report.

FPC P-38, *Hydroelectric Power Evaluation, Supplement No. 1, 1969*. Tables 10, 13, 15, 34, 38, 39, 40, 41, 42, 43, and 47 are the sources of data from this report.

Report of the Western United States - Central United States, study of transmission interconnection. The sources of data from this report are pages F1 and F2 and exhibit 9.

Handy-Whitman Index of Public Utility Construction Costs. The sources of data from this index are tables 3, 6, 9, 12, 15, and 18.

3 *Report of the Western United States - Central United States, study of transmission interconnection*. 1973.

4 Ibid., B-2.

5 Ibid., B-3.

6 0.03% × \$414 million = \$1.242 million; \$1,480 × 3,800 = \$5.624 million.

7 Ibid., p. F-7.

8 Ibid.

9 *WUS-CUS study*, p. F-7.

10 Ibid., p. F-8.

11 Ibid.

12 Federal Power Commission. 1972. *Study of proposed interconnection between Electric Reliability Council of Texas and Southwest Power Pool*. Fort Worth, Texas: Federal Power Commission. Bureau of Power staff report.

13 Matthews, Walter J. June 11-12, 1975. Impact of load management on regional reliability councils and power pools. *Proceedings of the Conference on the Challenge of Load Management - A convergence of diverse interests*. Washington, D.C.: The Federal Energy Administration, Office of Utilities Programs. p. 54.

14 These revenue requirements were developed for our revision of the economic analysis in the *Report of the Western United States - Central United States study of transmission interconnection*. The 14 percent per year includes all fixed charges including interest and insurance. See table 7.

15 Edison Electric Institute. June 1975. *Advance release of data for the statistical year book of the electric utility industry - year 1974*. New York, NY: EEI, Economics and Statistical Department. p. 7.

16 Ibid., p. 12.

17 This assumes that those who believe that the nation is quickly depleting its nonrenewable petroleum resources are correct.

18 These insights include national defense, environmental protection, or other considerations not easily quantified, even under extensive study.

19 See chapter 6.

Chapter 8
REGULATORY CONSIDERATIONS

Rates, land use, environmental concerns, financing, organizational structures, generation station siting, transmission line location and design characteristics, power pooling operations, and other aspects of the electric power industry of the United States are subject to various forms of control by local, State, and Federal authorities. For this report we mean to include all of these controls in the term "regulation."

Matters of regulation are most often directly or closely associated with legal concerns. We try to avoid the legal aspects--these are being addressed by the Congressional Research Service, American Law Division. However, the line separating regulatory considerations from legal aspects of a national power grid is indistinct, so the reader should consider this chapter together with the American Law Division's report.

Emphasis is on the general regulatory jurisdictions of the various agencies rather than on detailed analysis. However, questions about specific issues are raised to add emphasis. Widely differing economic and political philosophies of regulation and legal considerations make it impossible to answer here the questions we have raised, but the issues discussed provide a framework for detailed research, discussion, and debate.

PRESENT REGULATION OF THE ELECTRIC POWER INDUSTRY

The Federal Government is involved in many aspects of the electric power industry. All three branches of government are involved in some way. Table 8-1 lists various Federal organizations that operate in or regulate the electric power industry.

Direct regulation occurs mostly through independent commissions, mainly the Federal Power Commission (FPC), the Securities and Exchange Commission (SEC), the Federal Energy Administration (FEA), the Nuclear Regulatory Commission (NRC), and the Environmental Protection Agency (EPA). The Federal Trade Commission also has some jurisdiction over industry practices.

Regulation under the Executive Branch is through the Antitrust Division of the Justice Department and the Federal Energy Administration. Executive orders also serve to direct certain activities of the regulatory commissions. In addition, other executive departments are involved in generation

Table 8-1. FEDERAL ORGANIZATIONS INVOLVED IN THE ELECTRIC POWER INDUSTRY

Executive Branch

- Department of Agriculture
  - Rural Electrification Administration
  - Forest Service

- Department of Defense
  - Department of the Army, Corps of Engineers

- Department of the Interior
  - Energy and Minerals
    - Alaska Power Administration
    - Bonneville Power Administration
    - Southwestern Power Administration
    - Southeastern Power Administration
  - Land and Water Resources
    - Bureau of Reclamation
    - Bureau of Land Management

- Department of Justice - Antitrust Division

- Energy Research and Development Administration

- Environmental Protection Agency (EPA)

- Federal Energy Administration (FEA)
  - Office of Conservation and Environment
  - Office of Energy Resource Development
  - Office of Operations, Regulation, and Compliance

Legislative Branch

Passes legislation (such as the Federal Power Act) which establishes
defines the powers of various Federal organizations.

Judicial Branch

Rules on the legality of actions by regulatory commissions--a "check
their actions.

Rules on the constitutionality of legislation passed by Congress.

Independent Regulatory Commissions

- Federal Power Commission
  - Bureau of Power
- Federal Trade Commission (minor role)
  - Bureau of Competition
- Nuclear Regulatory Commission
- Securities and Exchange Commission
  - Division of Corporate Regulation

Other

- Tennessee Valley Authority

and transmission of electricity, but not specifically in regulation.

The Legislative Branch creates and defines the powers of the regulatory commissions and passes laws that are acted upon by the Justice Department and the courts.

The Judicial Branch interprets laws governing regulation and related disputes and, through its decisions, sets precedents that aid in defining the specific powers of regulatory bodies.

Most states have regulatory commissions where control is more specific than at the Federal level. They review operations, services, and costs, and approve rates of electric utilities. Jurisdiction of state commissions is, of course, limited to intrastate activities, although their influence is felt in other states. Furthermore, other state and local bodies are active in utility matters such as corporate activities, siting of facilities, implementation of state and local environmental statutes, and many others.

REGULATORY ISSUES

Implementing all or portions of a nationwide interconnected power grid has important ramifications on many facets of the electric power industry. Areas of major concern to utilities and regulators, and which can be affected by or can affect regulation, are:

1. Rates
2. Increased regional interconnection
3. Increased interstate transfer of power
4. Electric power wheeling
5. Reliability
6. Technical efficiency
7. Environment and conservation
8. Corporate organization
9. Industry structure
10. Jurisdictional conflicts
11. Regulatory effectiveness

It should be noted that even if a national grid policy *per se* is not adopted, these issues will continue to grow in importance because present trends toward greater inter-utility coordination are expected to continue. However, if a national grid policy is adopted and development of the national grid is accelerated, problems associated with these issues will be intensified. Therefore, Federal action appropriate to the policy course chosen will be needed. The issues listed above can all be managed through regulation, but the specific issue and the approach to managing it will also depend on the policy course or kind of grid chosen (see chapter 1).

Rates

The FPC has authority to review and approve rates charged for power sold in interstate commerce. It also reviews and approves rates for power sold intrastate for resale. Through its authority to regulate these selected rates, the FPC has jurisdiction over about 7.3 percent of the total electric power generated in the nation.[1] It is likely that this percentage, and therefore the extent of FPC jurisdiction over rates, will increase as a national grid is moved closer to completion. This is a likely result because of trends toward joint ventures in generation and because of different rates of growth in the demand for electricity in different regions.

Rates generally reflect costs of generation, transmission, and other costs of providing the service. Most sales of power are accomplished through contractual agreements between two electric utilities. Under some approaches to a national grid, these contractual arrangements would continue, carrying with them rates that reflect the costs of individual power producers. Under other approaches to a grid, uniform regional rates would reflect differences in the costs of producing power in different areas of the nation. Under still other approaches to a grid, rates would be uniform, reflecting national costs of producing and providing electric energy. Setting rates for power transmitted over the grid that would be most advantageous to the protection and advancement of the public interest is a controversial matter deserving considerable study and debate before decisions are made. The impacts of both uniform regional and uniform national rates would be significant and far-reaching. It would mean that consumers in low production cost areas, even within regions, could pay more for their electric energy than the costs incurred by the utility serving them. Conversely, consumers in high production cost areas could pay less than the costs incurred by the utility providing service. Equity and discrimination questions would demand attention.

Regardless of rate forms chosen to be applied in conjunction with a national grid, it will be desirable to provide strengthened rate regulation authority to ensure that rates reflect costs, that regional differences are recognized in rates and rate structures, and that rates are reasonable and equitable among and between consumer classes.

---

[1] See footnote references, end of chapter.

Furthermore, the strengthened regulatory entity could be provided the authority to expedite desirable and feasible interregional power transfers by assisting with the negotiation of interchange agreements and the regulation of associated rates.

Increased Regional Interconnection

A national power grid would entail building additional long-distance transmission lines among regions. Transmission lines to complete a national grid probably will be built sooner or later with or without a specific policy to have a national grid. So, the issues involving regulation are generally as much applicable to the present situation as to one involving a national power grid.

Regulation of interstate power transmission lines falls into three main categories. First, the FPC has some limited power to approve or require their construction.[2] The power applies to both privately owned utilities and publicly owned utilities only in emergency situations.[3] Nevertheless, the FPC has vigorously encouraged voluntary interconnections in recent years.

The efforts of the FPC have mainly been in assisting utilities to determine the feasibility of interconnections. The FPC's 1964 and 1970 National Power Surveys provide a great deal of information for and about this activity.

If a policy is adopted to accelerate completion of a national grid, the implementing legislation could provide for greater FPC involvement in power system planning. It could also strengthen FPC authority to require interconnections. Furthermore, requirements for interchange of power under conditions other than emergency may be necessary to make certain that all potential advantages of a national grid are obtained. This would require considerable extension of existing Federal regulatory authority.

There are instances when actions of local or state regulatory bodies hamper or prevent regional interconnections. In recent years such actions have often involved environmental regulation. In Delaware, routing objections have delayed for 5 years a 500-kV transmission line considered to be an important link in the Pennsylvania-New Jersey-Maryland (PJM) Pool network.[4] Opposition to coal-fired powerplants and to interstate transmission lines is hampering development of major generating facilities with multiple owners by utilities operating in two states.

Such actions indicate that efforts to strengthen regional interconnections and to undertake large-scale power supply projects involving multistate activities may need some form of regulatory encouragement through the creation of multistate compacts, Federal regional agencies, or strengthening of existing Federal regulatory authority so that selected individual state jurisdiction over generation and transmission siting could be preempted.[5] Present legal mechanics for allowing interstate compacts require Federal action. This avenue to coordinated, mutually beneficial regulation of the electric power industry may be cumbersome. Therefore, additional Federal legislation providing for required multistate regulatory cooperation would be needed. If this approach were deemed unworkable, recourse could be had through Federal regional agency creation or strengthening existing Federal regulatory authority. In the most fundamental case, regional development (and regional differences in the demand and supply sides of the power industry) requires that regulation look beyond state boundaries. We believe serious national debate is needed on this point.

Second, the high cost of constructing long-distance transmission lines and large powerplants has necessitated cooperative planning and joint ventures among utilities to raise adequate capital for construction. We conclude that access to adequate capital can be obtained through these methods. However, if such efforts are thwarted, an alternative would be Federal involvement in the form of Federal construction of generation and transmission projects, or Federal guarantees of the private debt needed for such projects.

Multicompany agreements are needed to ensure efficient use and to provide for orderly operation of large, new facilities. The formation of new and/or larger powerpools could bring members of the electric power industry under the scrutiny of the SEC, the Antitrust Division of the Justice Department, and the NRC. Refusals by some utilities either to join powerpools or to allow other utilities to join pools could be construed as an exercise of monopoly power. These issues are discussed further in subsequent parts of this chapter.

Third, the EPA would be involved with the environmental aspects of transmission line, substation, and powerplant siting. Environmental issues and aspects are discussed below and are treated in more detail in the study "A National Power Grid System and the Environment," prepared by the Congressional Research Service, Environmental Policy Division.

Increased Interstate Transfer of Power

One purpose of an interconnected power network is to realize cost and energy savings as a result of increased transfers of power. To the extent that utilities are interconnected but do not participate in economically desirable coordinated transfers, these savings are not being realized. Unwillingness to interchange power could result from a desire by one company to conserve its primary energy resources as a hedge against future uncertainty, from a wariness of increased regulation, or from a reluctance to give up individual utility autonomy. Furthermore, intraregional planners and leaders and state regulatory authorities may question the long term effects on their region or state of "exporting" their energy resources to other regions via wire.[6]

A central issue is whether the residents of a region have exclusive or even first claim on the energy resources of that region, or if the resources belong to the entire nation. (All of an area's natural resources are subject to this issue.) Federal legislation has provided a form of regional priority for hydroelectric power produced in the Pacific Northwest.[7] This regional "first call" is not established explicitly for other regions, however. Concerns are being raised in many states about using fuel, air, water, and land resources of the state in order to provide electric energy for another state.[8] Resolution of the issue will require clarifying litigation and Federal legislation.

This raises the issue of whether the FPC or another regulatory agency should require utilities to sell bulk power to other interconnected utilities under other than temporary emergency conditions. According to Breyer and MacAvoy,

> "The Federal Power Commission has . . . undertaken a program to add to the quality of service in electricity generation. . . . This program has centered on requiring the larger producers to provide power to small retailers with whom these producers would prefer not to do business. So far, the campaign has had little effect . . ."[9]

The courts have consistently upheld the Commission's authority to compel the sale of power to a municipality subject to the conditions provided in section 202(b) of the Federal Power Act.[10] Additional complaints may result in orders by the FPC directed toward power companies who are unwilling to interconnect and sell power, when to do so is in the public interest and would not impair the selling utility's service to its own customers.

With a national grid operation, there would be questions concerning extent of the FPC or other regulatory agency jurisdiction over electric utilities that operate entirely within one state. Intrastate utilities may need to connect with a grid to ensure the realization of economic and operational potential. Regulatory agencies would have to have jurisdiction over operations under normal as well as emergency circumstances to accomplish this aim. Furthermore, authorized regulatory controls over interconnections and participation in coordinated system operations would need to be vigorously exercised; otherwise, many advantages of the interconnected network may not be realized.

Electric Power Wheeling

Wheeling refers to the utilization of transmission facilities of one company to transmit power of another company. This practice is common in the electric utility industry and has the economic and environmental benefits of avoiding the construction of duplicating transmission facilities. Wheeling also gives utilities access to power supplies from low-cost producers some distance from their load centers. Widespread wheeling, compulsory or voluntary, would permit transfers of power between noncontiguous regions (such as NPCC and SPP or ERCOT) and would enlarge the potential benefits of a national grid.

Breyer and MacAvoy believe the FPC has the authority to require wheeling. They hold that officials of the FPC:

> ". . . read the Federal Power Act narrowly. Section 202(b), which gives it authority to compel interconnection, was construed to apply only to the joining of wires, not to the carrying of power across them. The commission did not mention other possible sources of legal authority to compel wheeling, such as Section 205(b) (no public utility shall 'subject any person to any undue . . . disadvantage') or Section 207 (the commission can require utilities to provide 'proper, adequate, or sufficient [interstate] service')."[11]

They seem to raise a legal argument with FPC activists who have vainly sought legal basis for such authority. However, in the Ottertail Power Company case,[12] the Supreme Court stated explicitly that the FPC has no authority to compel wheeling under part II of the Federal Power Act. In the adoption of a national grid policy where existing industry structure and operations are incorporated, authority to require wheeling will need to be given to some Federal agency, probably the FPC or FEA.

As noted in chapter 5, we believe that any wheeling proposal should be preceded by technical studies to establish whether the proposed wheeling can be accomplished without adversely affecting existing facilities or operations. From this follows an important regulatory aspect of wheeling, the question of whether regulatory authorities could require investment in additional transmission capacity if it were necessary to wheel power but not necessary for normal utility operations. This would be a substantial extension of FPC powers beyond present interpretation of the statutes and court decisions defining the FPC's jurisdiction. Legislation would probably be required to implement a policy of requiring transmission systems to be designed to accommodate yet unspecified wheeling transactions. The amount of extension of Federal authority and the place chosen for it to reside will depend greatly on the specific approach selected for development of a national grid.

Antitrust considerations also enter into the issue of wheeling power. A refusal to wheel power (if the capability existed) could jeopardize the competitive positions of other utilities, particularly small companies. Their costs of electricity would most likely remain high since access to economy energy would be forestalled. Refusal to wheel would thus be subject to Justice Department action under the Sherman Antitrust Act. The Ottertail Power Company case upheld the courts' power to compel wheeling in such cases. Refusal to wheel is an issue in some current antitrust investigations of the Department of Justice and the Nuclear Regulatory Commission in connection with licensing of nuclear powerplants. Refusal to wheel under a national grid policy would make such investigations a matter generally applicable to nuclear and non-nuclear generation.

It is sometimes suggested that the "common carrier" concept be applied to the transmission of electricity. This would put utilities in a position of having to establish rates for wheeling and making that service available to all parties. There is industrywide resistance to this concept on the grounds of its potential constraint on flexibility of operations. However, if such a concept were adopted, it could force utilities to install transmission capability in excess of that needed for their own operations. Rates for such wheeling service would be subject to regulation. This would be regulated by the FPC or other agency if the necessary extension of authority is provided.

Under a few approaches to a national grid, "common carrier" wheeling would be the responsibility of Federal agencies, national or regional, given the authority and responsibility to establish and operate the grid. Rates for wheeling services would then be a matter to be determined by the Federal agency and approved by an overseer agency such as the FPC.

Reliability

A major potential advantage of a coordinated national grid is improved overall electric system reliability while reducing or holding constant operating reserves. An important corollary benefit could be the assumed ability of the nation's electric utilities to cope better with major emergencies, such as manmade or natural disasters affecting electric supply facilities. Coordinated interconnections allow timely transfers of energy to areas short of generating capacity. Since the well-known power failure in the Northeast in 1965, reliability planning has been a major activity of the FPC, with the general cooperation of the electric utility industry.

The FPC is assigned the task of setting priorities among customer classes during periods of short supply.[13] Other than this specific power, the electric utilities are guided by the general admonition to provide reliable service to all firm customers.

In chapter 4 we have raised questions relating to the possibility of reducing electric utility generating reserves by maintaining lower standards of system reliability and by establishing different reliability standards for different classes of customers. Such methods could be desirable from an operations and economic standpoint. There would be a need for uniform administration of reliability standards. This might well be handled on a largely voluntary basis as is now done through activities of the National Electric Reliability Council; however, some regional or national control by a regulatory body, perhaps the FPC by extension of its present authority, would appear desirable.

Any deliberate reduction of reliability standards would raise questions of legal liability in the event of damages caused by a power outage. The legal question seems to us to be probably more complicated if different reliability standards are applied to different classes of customers. These legal as well as the technical questions would have to be resolved before reductions in reliability standards (and thus operating reserve requirements) could be made in this manner. Currently, under sections 202(b) and 207 of the Federal Power Act, a utility is required to provide adequate and sufficient service. The FPC may find it necessary to compel a minimum level of reserves because service below some unspecified level of reliability would be considered inadequate and insufficient.

Accelerated implementation of a national grid would probably not change the emphasis of regulatory policy regarding reliability, but the scope of that task would be substantially increased, particularly if different reliability standards are prescribed and maintained for different customer classes. A mechanism for enforcement and an avenue for processing complaints of injury or discriminatory treatment would be needed.

Technical Efficiency

Coordinated planning is vital in the design and efficient operation of all components of a national grid. Interconnection of electric power supply systems across the country would pose important technical problems that will receive the attention of regulators. These include synchronization of generation facilities; time error control; sizing and location of major generation and transmission facilities; and design and operation of systems to collect generation, load, and operational data and communicate it to system operators to achieve efficient regional and national power transfers.

The extent of regulatory jurisdiction over technical aspects of system planning and design has been limited in the past but may need to grow if an accelerated national grid policy is pursued. For example, should regulators be empowered to dictate design and equipment specifications to utilities because they are connected to a national grid network? It is possible that regulatory powers over technical aspects would be needed with an accelerated national grid program and may be desirable as the present interregional networks are strengthened.

It should be noted that the Federal Energy Administration, in the interest of petroleum conservation, has ordered utilities to convert from gas- and oil-burning powerplants to coal-fired plants. This is a costly procedure involving technical changes to existing equipment and the addition of new equipment. Thus, regulation which affects technical aspects of electric supply does occur.

A final question regarding technical efficiency needs to be raised. How does regulation influence the rate of technological innovation? Critics argue that incentives are reduced by regulation, while others contend that regulated intercompany cooperation leads to a better flow of ideas. The long history of utilities, with some exceptions, engaging in little or no research until Congressional action stimulated the formation of the Electric Power Research Institute (EPRI) is one piece of evidence that regulated industries.

tend to be slow to innovate. Nevertheless, this unresolved issue is important in any consideration of regulatory philosophy relating to a national grid.

The mere scope of these technical matters requires that the particular approach chosen to achieve a national grid be carefully matched by a regulatory mechanism with appropriate authority, responsibility, and funding. The regulatory agency should receive frequent and in-depth review by the Government Accounting Office (GAO) and the Congress.

Environment and Conservation

These two interrelated issues are briefly discussed here. A more detailed treatment of the environmental aspects of a national power grid system is covered in the studies being done by the Environmental Policy Divison of the Congressional Research Service.

The environmental impacts of the physical features of a national grid include aesthetic values, land use, air pollution, thermal and other pollution of waterways, radiation, socioeconomic, and possibly biological effects on humans and animals near UHV high-voltage transmission lines.[14]

At the Federal level, the EPA has responsibility to monitor environmental issues. At the state and local level, numerous formal and informal bodies have an interest in environmental impacts. Formal public hearings are typically required before any large facilities can be built, and judicial review often follows.

An important environmental aspect of interstate transfers of power is "exporting" pollution. If one region imports power from, say, coal-fired "mine mouth" plants in another region, the air and thermal pollution from that plant occurs in the region where the power is generated, as a result of power used by residents of the other region.[15] Depending upon decisions to be made regarding fuel use and powerplant siting relating to the use of coal resources, this type of situation may become more common.

It is not clear now whether acceleration of a national power grid would tend to stimulate more remotely sited powerplants with an increase in the "exporting pollution" problem or whether decisions in favor of remote powerplants will be a strong factor in strengthening interconnections and even completing presently unjoined sections of a national power grid, such as ties between the West Coast and central United States. We believe the latter is the more likely case. A determination of the equity issues among affected regions will be needed and could best be done by regulatory authority at a multiregional or national level. Certainly more is at stake than local or state concern.

Since 1969 the FPC has been involved with environmental protection. "An office of the Advisor on Environmental Quality has been created (in the Bureau of Power), and a Task Force on Environmental Questions was established."[16] The regulatory function of these groups has been slight, but recognition of environmental problems certainly is enhanced. Coordinated planning for capacity by utilities is a way to reduce needs for new construction and thereby will reduce potential environmental impacts. Yet, there is a need to monitor the cooperative planning from an antitrust point of view while encouraging the cooperation from an environmental protection point of view. Divergent regulatory interests could lead to jurisdictional disputes. The potential for violating the public interest will require monitoring of the regulatory agencies.

An interrelated topic often identified as an environmental issue itself is the need for efficient allocation of scarce energy resources. This is a main concern of the FEA. The thrust of FEA actions recently has been to reduce U.S. reliance on foreign energy resources--mainly petroleum--and increase use of domestic coal supplies.

As mentioned previously, the FEA has directed a number of utilities to convert from oil to coal. Manipulation of energy transfers over a national power grid could help accomplish these objectives. For example, transfers of large quantities of electric energy from the Midwest to the East Coast would allow power from currently oil-fired plants in the East to be displaced by coal-generated power. The so-called "coal-by-wire" decision of the FPC[17] shows that the FPC and FEA are cooperating in such matters now, and the strengthening of interregional interties will make the issue more important.

However, to the extent that energy exchanges to effect conservation of specific fuels may not always have favorable economic benefits, regulatory action will be needed to allocate costs among the parties, and legislation may be desirable to permit the Federal Government to absorb some costs as a matter of public interest. This matter is related to the adoption of a national grid policy through the grid's potential provision of access to western coal and other currently isolated coal deposits by utilities of the southwest, south Texas, and middle Atlantic and New England states.

Finally, the FEA and utility commissions in many states have been studying possible changes in electric rates and rate structures as a means of stimulating the conservation of energy. A national grid could intensify involvement by the FEA and others in rate regulation. It is conceivable that changes being promoted in rate structures such as peakload pricing and inverted rate forms may save energy but actually sharpen peakloads on the hottest or coldest days, thus resulting in increased load diversity between regions. Regulators then could require interregional exchanges of diversity capacity to be made available as a result of rate-induced changes in demand patterns. On the other hand, if the objective of FEA and others to reduce peakloads by flattening the peaks of the load curve is successful, diversity would be reduced. Control of rates and rate structures is a regulatory matter of great importance. The authority for rate regulation should be placed in the hands of an agency with significant knowledge and expertise in this matter. Just how consumers will respond to specific rate changes will remain an unknown until widespread application of experimental rate design is instituted. We recommend more pilot and demonstration projects in rate design prior to final imposition of national or regional rate reform.

Corporate Organization

The structure of holding companies operating in the electric power industry is closely regulated by the Securities and Exchange Commission (SEC). After passage of the Public Utility Act (1935), the large holding companies that were formed between 1917 and the mid-1930's were largely reorganized. Since 1935, the SEC has maintained close control over holding companies' and the industry's structure.

Economies of scale in transmission and generation motivate utilities to consider consolidating power systems. This inclination could become stronger if a national grid policy is pursued. A related matter is the effect interconnection has on the physical and legal relationship of electric utilities. This is important in interpreting SEC powers to control holding companies. Presently, separate companies that are in noncontiguous states and are not interconnected cannot be operated by one holding company. An operational national grid would provide a capability for two such separated systems to operate as one. Perhaps under the closer regulation that would result from the establishment of a national grid, such separated systems could be owned by a single entity. This may be justified on operational and economic grounds, but it would require a significant change in the present laws under which the SEC controls the merging of utilities through the holding company vehicle.

It is not likely that SEC jurisdiction and influence over the industry structure will be significantly changed as the result of a strengthened interregional transmission network, unless there is a change in the basic philosophy underlying the Public Utility Act of 1935. However, if injury to the public interest is to be prevented, the SEC will need to maintain a constant and close monitoring of the industry if an investor-owned national grid becomes operational.

Industry Structure

Cooperation in facilities planning and in operating interconnections opens the way for possible significant changes in industry structure. Changes could occur in the following areas: formation of more powerpools and consortia for generation and/or transmission; mergers, both "vertical" and "horizontal";[18] increased competition in most wholesale and selected retail markets; increased access to interregional power by public and private utilities; and changes in market shares of public and private power.

Powerpools and consortia are being formed today to capture the benefits of economies of scale and improved reliability. Large powerplants and transmission lines require very large amounts of capital investments that often can be raised only by cooperative efforts. Yet, interutility cooperation presents opportunities for unlawful collusion among producers of electricity. Mergers are another means of combining financial resources and realizing economies of scale. Both interutility cooperation and mergers make possible the violation of the public interest unless precautions are taken and interfirm relationships monitored.

Powerpools and mergers affect the structure of the industry and thereby reduce the extent and change the nature of competition. Mergers can strengthen the monopoly position of utilities. (Whether or not they actually act as monopolists is another matter; but the ability to so act exists nevertheless. The mere existence of such ability could intimidate consumers or other producers.) Powerpools, mergers, and consortia among large companies can be anticompetitive in nature, particularly in the wholesale market, by putting smaller producers at a production-cost or wholesale-cost disadvantage.

Refusal to allow a utility to join a powerpool or consortium would be an exercise of monopoly power. The competitive disadvantage to which the refused utility is put is evidence of the strength of that power. The Sherman Act long ago condemned such monopolizing. Therefore, cooperation among all regulatory agencies should be encouraged to assist the Justice Department in policing the monopoly power of the utility industry in both the short and the long run.

Smaller electric utilities increasingly are seeking relief, through the antitrust laws or through the antitrust reviews associated with nuclear powerplant licensing procedures, from activities of larger companies that have limited or blocked the smaller companies' access to wheeling low-cost wholesale power and the many benefits of powerpooling. A national power grid operated in the public interest by a Federal agency or other publicly oriented entity would be of significant benefit to the smaller utilities.

Competition occurs in differing degrees in both wholesale and retail markets in the electric power industry. Competition in retail markets is minimal because service areas usually are well defined by regulators. However, utilities do compete to serve new retail loads, such as certain subdivisions, and industrial and commercial operations.

Competition at the wholesale level is also limited because of the large amount of vertical integration in the industry. Large producers or consortia may compete for bulk sales to utilities that need extra power for resale. However, such competition is generally limited by contractual agreements between producers and retailers.

It is difficult to estimate the effect a national grid would have on competition. Leonard Weiss suggests that generating firms or groups might compete for wholesale loads if transmission is made more economical.[19] Weiss notes that questions about state "antipirating" laws may arise, but that wholesale loads for resale appear to be beyond state jurisdiction.[20] On the other hand, a 1975 report by Nuclear Regulatory Commission staff economists states that coordination ". . . may decrease the likelihood of wholesale load competition for firm power (but) it can maintain the viability of smaller systems."[21] The actual effect of a grid on competition will, of course, be of major concern to regulators, particularly those of the Antitrust Division of the Justice Department.

Changes in the relative roles of publicly owned and investor-owned bulk power producers might accompany increased inter-utility coordination. First, publicly owned retail utilities, such as municipal electric systems, are given preferential treatment in purchasing power produced by Federal bulk power producers. This, however, enhances their competitive position relative to investor-owned utilities. Increased transmission of public and private power over a national grid may provide the basis for another series of battles over the equity of such preferential treatment of publicly owned electric utility systems. The drafters of legislation must be exceptionally cautious of inadvertently doing damage to policy that has been laboriously brought to its present state to protect the public interest.

Second, the costs of production as accounted by publicly owned utilities are often lower than those of investor-owned utilities; this comparison is frequently cited and is called "yardstick competition." The comparisons are detailed and complicated. A comparison must be made cost-item-by-cost-item insofar as possible. Adjustments for implicit costs, hidden taxes, payments in lieu of taxes, and other cost differences must be made. The result allows regulators to make conclusions about relative performance of public and private power producers. The apparent cost differential has been related principally to the lower interest rates, lower tax obligations of the publicly owned utilities, differences in executive salary rates, and the need for the investor-owned utilities to return a profit to stockholders. However, when adjustments are made in the various accounts, performances do not appear greatly different. The apparent differences in specific cost accounts sometimes complicate otherwise desirable joint power supply efforts of publicly owned and investor-owned utilities.

A national power grid, which would provide closer interrelationships among utilities, could result in economic and political pressures for legislation at national, state, and local levels directed toward reducing the cost differentials for specific accounts between investor-owned and publicly owned utilities. If this occurs, the full range or the differences in costs must be assessed rather than just the interest, taxes, salaries, and profits differentials. Otherwise, distortions of the equity between public and private power interests would occur. Furthermore, the usefulness of the "yardstick" as a regulatory test would be diminished.

Some public and private corporations have formed for the sole purpose of constructing and operating electric generation and transmission facilities. Many of these provide power supply to utilities in two or more states. Examples of these generation and transmission (G&T) agencies include Connecticut Yankee Atomic Power Company; Electric Energy, Inc. (Illinois, Kentucky, Missouri); Colorado Ute Electric Association, Inc.; Basin Electric Power Cooperative (North Dakota); Tri-State G&T Association, Inc. (Colorado, Nebraska, and Wyoming); Washington Public Power Supply System (Washington, Oregon, Idaho, Montana); Buckeye, Inc. (Ohio); and Tennessee Valley Authority (Tennessee, Alabama, Georgia, Mississippi, Kentucky, North Carolina.)

As previously noted, the highly capital-intensive nature of the electric utility industry, especially the very high costs of generation facilities, has stimulated increased cooperation among utilities in the forms of joint ownership of projects or separate G&T organizations. Strong regional transmission networks are essential to the success of most joint generation and transmission projects. For these projects, wheeling services over existing transmission systems where capacity exists is desirable to avoid duplication of facilities. While increasingly stronger regional transmission networks are being constructed, the often complex contractual arrangements for ownership and operation hamper and probably frustrate efforts at joint action by large numbers of utilities. Bringing together the diverse interests of Federal agencies and individual investor-owned, publicly owned, and cooperative utilities, as is being done in the Pacific Northwest and other regions of the country, is a trying process, to say the least.

Help in resolving such problems may be found in the suggestion of the Ford Foundation Energy Policy Project.

> "Reforms in the structure of the industry to separate the generation and transmission of electricity from local distribution are desirable. This would facilitate the formation of regional companies, with public participation in their management, to achieve the economies in capital and land use that are possible in an integrated regional approach to power system expansions."[22]

Such a fundamental change in industry structure would require changes in public policy by legislative action. Depending upon the authority granted to such regional companies, the autonomy of existing individual utilities would be threatened, and many of these utilities, both publicly owned and investor-owned, would offer strong opposition to the regional G&T company. Regional G&T companies, each under a single management, would aid in furthering benefits of coordinated planning and operation of the utility industry.

In spite of the considerable progress across the nation toward coordinated electric system operation, there is intense desire on the part of virtually every utility that we know to reserve considerable rights to independent action. Agreements for powerpooling are now carefully and laboriously drafted to preserve this independence while providing for a substantial degree of coordination. This is a natural result of the existing industry structure; it would be difficult for individual utility managers to answer to their directors or governing bodies if important prerogatives of the individual utility are subordinated to broader regional interest. Presumably a regional G&T company could easily take a regional view. On the other hand, a regional company, even if publicly owned, would be viewed by many as a "super agency" lacking direct control by the public. Whether such a charge would be sustained would, in part, depend upon the details of the structure of such a corporation.

We do not endorse the regional G&T company idea at this time because of the lack of specifics as to the nature of such a company; however, the concept has sufficient merit to warrant serious public consideration. Regional G&T companies could both aid in further development toward a national power grid and result from such development. If properly conceived, regional G&T operations could solve a majority of the current problems of pooling and coordination and they would avoid much of the ongoing controversy over individual system management autonomy.

In summary, changes in the structure of the electric utility industry will likely be required to further a national grid. Conversely, a national grid will probably provide impetus for change in the industry's structure. In either case, the need for increased coordination among utilities will result in pressure for change. Existing regulatory agencies should have expanded roles to cope with the regional and national aspects of the electric power industry. Or, if existing or expanded authority of current regulatory bodies is insufficient, new regional or national agencies will be needed to monitor and control concentrations of corporate power to prevent development leading toward a national grid being used to the detriment of the public interest. The specific approach chosen for development of a national grid will determine the type of regulatory organization and its powers needed to protect the public interest.

Jurisdictional Conflicts

Responsibility for regulation of the electric power industry is diffuse. Numerous Federal and state authorities have jurisdiction over various phases of utility existence and operations. In many cases regulatory powers overlap, and conflicts arise as to which agency has primary jurisdiction. Conflicts occur among Federal agencies as well as between Federal and state agencies. Most of the conflicts discussed below currently are problems. However, if a national grid is completed, disputes in these areas are likely to increase.

Lack of consistency in rules and regulations is a result of diffuse regulatory authority. For example, state commissions use different standards in establishing rate base, rate of return, levels of rates, and rate structures. The FPC reviews wholesale rates and financial data from virtually all U.S. electric utilities, public and private. If the interconnected power systems are treated as serving a national market, then standardization of many major and minor regulatory practices becomes desirable to facilitate realization of the full potential of coordinated operation.

However, as desirable as consistency of regulation may be, important regional differences influencing power system characteristics must be respected in developing industry and regulatory standards. Regional factors that must be considered include: geographic features, weather patterns, fuel resources, generation mix, load characteristics, and general economic base. All of these and perhaps many other factors influence individual system's operating characteristics and therefore their operating costs.

The issue of requiring interconnections, discussed earlier, could foster disputes between Federal and state regulators. The FPC and other Federal authorities, concerned with the overall technical and economic efficiency of a nationwide interconnection of electric power systems, may need to have their authority extended so that intrastate utilities may be required to interconnect. On the other hand, a state commission may be reluctant to allow utilities in its own state to contribute financial support to, say, out-of-state transmission lines ". . . unless it is perfectly clear that customers in its own state will benefit."[23] We conclude that a specific change in public policy would be needed to accomplish full and firm nationwide interconnections. We cannot make a recommendation here about this change. However, we foresee several possible occurrences of a functional need for such a policy change and the granting of this preemptive authority.

Related to the issue of granting of authority to require interconnection in other than emergency and temporary conditions is that of the power to monitor utility operations after interconnection. Federal or regional authorities (if Federal or regional approach is taken toward a grid policy) may need power to require an in-state producer to sell electricity out of state. Otherwise, the authority to require interconnections may be ineffective in achieving the objectives of establishing a national grid. We note again that the specific authority and the agency to which it is granted will depend on the alternative approach chosen to establishment of a grid.

Rates are regulated by state commissions and, to a limited extent, by the FPC. They are influenced by the FEA and others through intervention in rate cases presented before state utility commissions. Presumably, the FPC could be granted primary jurisdiction over rates charged for interstate power sales if a national grid as a discreet power network is established. It may be necessary, however, to set rates for power sold into a national grid and taken from a national grid. This would be a striking departure from current interutility power sales contracts and agreements for the wheeling of the power. Such grid rates might be on either a regional or national basis. A major problem in such an effort is the nondistinguishable nature of transmitted electricity, which makes it impossible to differentiate between power generated by different firms (with different costs) and sold into the grid. Thus, using production costs for allocating revenue requirements and determining rates would be equally impossible. Federal and state agencies may dispute control over rates. Certainly, disputes would arise over equitable distribution of the costs of producing the power.

Another aspect of rates is the concept of rates designed to encourage conservation. Rates to stimulate conservation of energy have been studied by the FEA in particular, and also by state regulatory agencies. If the FEA were to attempt to institute conservation rates in one area and not in others to accomplish national goals, conflict with state commissions, and possibly with other Federal agencies over equity of rates would probably occur. Under conditions of a national grid where access to electric power is established for all regions, equity of interregional rates will become an important issue.

If regions are interconnected, conflicts may develop regarding "rights of first claim" over regional resources. We have already touched on such conflicts in discussing increased interconnections. Among regions, electricity may be generated in one region using that region's coal reserves. Transmitting the power to another region is functionally tantamount to shipping the coal out of the first region to be used in a generating plant in the second region. (The actual method used, shipping coal or transmitting electricity to the place of ultimate use of the electricity, is generally resolved on economic considerations.)

Thus, if the FPC, the FEA, or other Federal agency orders interregional power transfers, it would be requiring a region to give up some of its energy resources. The so-called "coal-by-wire" decision of the FPC addressed this issue to some extent.[24] Serious conflicts between national, regional, and state authorities, involving both economic and environmental interests over this issue, have occurred. These conflicts could intensify when interregional interconnects are even stronger and if a national grid becomes a reality.

During the oil embargo emergency of 1973-74, the industry, including public-, private-, and consumer-owned utilities, engaged in long-distance transfers of large quantities of bulk power from the Midwest, Southwest, and Southeast to the Middle Atlantic and Northeast areas. Relief was provided to oil-short utilities that could not quickly convert to coal-fired generation because of environmental protection or equipment constraints. The transfers and the accounting for the power went well in the emergency. It required extraordinary diligence and patience of all cooperating parties, however.

In normal operations, voluntary cooperation may be considerably less. Ensuring the capture of full potential of a national grid, averting refusals to deal, withdrawals of power in nonemergency conditions, and other disruptive actions will require overriding authority. Thus, when transcending state lines in transmission of power, we focus on Federal involvement. We conclude that, for a full-fledged national grid to be established, function smoothly, and yield its full potential to the nation, there will have to be specific compulsions provided by legislation. The legislation also must provide for concomitant regulation for the existing public and private facets of the industry to be coordinated together to ensure that the national public interest is protected. Such coordination would help even the existing voluntary pools since the authority at the Federal level would remove the need to protect individual system management autonomy.

Environmental impacts of a national grid could be an area of dispute between government agencies. The EPA and state and local environmental groups are responsible for ensuring that new construction and system operations will not unduly harm the physical and manmade environment. The FEA is charged with the responsibility to ensure availability of domestic fuels, such as coal. Decisions as to tradeoffs between strip mining and burning coal and importing oil could thus be difficult.

Here again, we see evidence that as the electric power industry becomes more regional and national in its planning and operations, the public interest will require that these various conflicts be resolved. A national agency, or regional regulatory agencies with broad authority, would be important alternatives worth public examination in an effort to seek needed resolutions to these conflicts.

Regulatory Effectiveness

Regulators are often frustrated in their efforts to control utility operations to protect the public interest over the long run. The effectiveness of regulation in that light is a perennial issue. It has stimulated research, Congressional hearings, and debate, but the issue has not been settled. Acceleration of the development of a national grid will magnify the problems associated with the regulatory-effectiveness controversy. However, adoption of a national grid policy automatically presents opportunities for directly treating problems that contribute to regulatory ineffectiveness.

Among the problems are diffusion of power, vague or unspecified goals, capture of regulators by the industry they regulate, lags in the regular regulatory process, and lengthy delays when regulatory conflicts go to adjudication. Diffusion of power leads to uncoordinated regulatory efforts, sometimes aimed at opposing goals; regulation in these cases becomes more a part of the problem than the solution. On the other hand, the diverse ideas of regulatory authorities could tend to stimulate innovation and cooperation.

Vague and ambiguous language in the statutes providing for regulation of the industry make the regulatory task more difficult. Goals of regulation in many instances have not been clearly and sufficiently defined to delineate roles of regulation. Moreover, many goals that have been clearly specified often have not been pursued. Breyer and MacAvoy contend that the FPC ". . . let its priorities be set by external pressures."[25] These two authors recommend adherence to defined goals rather than submittal to external pressures.

Time is an important element in the regulatory process. Regulatory agencies at the Federal level are typically so large, have such circuitous work procedures, and normally self-imposed heavy workloads that it takes a substantial amount of time to initiate any definitive actions. Judicial review is also time-consuming.

Industry attitudes toward regulation play an important role in finally determining the effectiveness of regulation. Some utilities have avoided joining powerpools or selling power out of state.[26] Fear of increased costs due to regulatory "red tape" is thought to have been the course of such actions.

Critics of the regulatory agencies have suggested many ways to cure their real and alleged ills. Even if a national grid policy is not adopted, two major areas offer opportunities for improvement. Existing regulatory agencies should increase their communication and coordination among themselves. Review of goals and jurisdictions could aid in this effort. In addition, industrywide planning and coordination could be emphasized along with rate design and other specific topics. Information gathering on a uniform basis and broad scale would be an important part of this rearrangement of emphasis.

Also, the regulatory agencies need to establish and pursue firm long-range goals. Short-run activities and "emergencies" should be dealt with within the long-range context.

In the event that a national grid policy is adopted, however, much could be accomplished in addressing problems that reduce and infringe on regulatory effectiveness. Diffusion of power would be directly addressed through establishing regional or national agencies charged with regulation of the industry as it interfaced with a grid. As noted, much of the regulatory prerogative held by the several states would be assumed by multistate or national regulatory agencies. This would promote the specification and standardization of regulatory approaches and regulatory goals, but would allow regional differences to be recognized. Furthermore, regulatory efforts would be much easier to coordinate. Communication between agencies would encourage innovation. Rules of different regulatory bodies could be directly addressed and conflicts eliminated. Coordination and cooperation among the new agencies that are created and between new and existing regulatory agencies would keep the setting of goals and priorities in the open, avoiding or reducing the influence of external pressures.

Legislation extending the current power of the Federal regulatory establishment or creating new regulatory agencies concomitant with the type of grid chosen, should specifically address the problem of time delay in the regulatory process and that associated with the adjudicatory process. Studies are needed of these processes to identify current and potential "bottlenecks" and ways to eliminate or circumvent them. The interests of the public as well as that of the utility industry and its regulators would be benefited. Concerted efforts must be made to streamline the regulatory process whether a national grid policy is adopted or not. Streamlining is particularly important if a grid policy is adopted.

The capture of the regulatory process by the regulated industry has long been thought to be a problem. There is no need to establish two camps of adversaries, the industry and the regulators. The public is likely to suffer. To regulate an industry, regulators must be familiar with the details and the broad spectrum of the entity being regulated. In the past, it has been easier to select knowledgeable people from the industry to serve as regulators and staff personnel. These new personnel automatically bring with them subtle aspects of the industry. New regulatory approaches could be attained if regulatory agencies built up technical and regulatory expertise independently and established credibility through performance. Mutual respect would be beneficial in the regulatory process and the public interests would benefit.

Finally, the ultimate effectiveness of regulation often rests with the philosophies, intelligence, and judgment of the regulators. The process by which regulators are selected, therefore, must be carefully considered in any legislation amending existing or establishing new regulatory authority.

We believe that the electric power industry has developed to a point that it now must transcend state boundaries. Therefore, some form of multistate, regional, or strengthened Federal regulatory bodies needs to be created to manage those aspects of this complex industry of critical national importance. The basic aim of this new authority must be the achieving of benefits of increased utility coordination, or new technology, and of a national grid. Fundamental to all of these aims, however, is that of designing agencies, defining regulatory functions and procedures, and prescribing authorities such that the operation of the industry is facilitated in the public interest in both the short and the long run. The type of grid chosen will determine exact specifications of the regulatory function.

REGULATORY IMPLICATIONS: AN OVERVIEW AND SOME GENERAL CONCLUSIONS

A national power grid is, of course, a concept that has enormous flexibility to it. As perceived by many in the electric utility industry today, there is a national power grid to the extent now practicable. To other observers, the existing transmission links among regions in the country are uneven and require considerable beefing up if there is to be a network that could be described as a national power grid.

Quite obviously, the character and complexity of the regulatory treatment of a national power grid is closely related to what fundamental decisions are reached by this country in developing a grid. If all we are talking about is techniques for encouraging the voluntary system now in effect, either through tax subsidies or other inducements, including exhortation, very little additional regulatory problems are involved. However, even here, the increasing multistate issues need to be provided for.

If we move up the spectrum of possible organizational changes, for example, to the point where newly created private corporations are created only for transmitting electricity (or possibly for generating and transmitting electricity), a new set of regulatory problems will require resolution. Obviously, if the decision is to have the Federal Government play a major role, either in constructing, owning, or operating a grid (or parts of it), yet a different group of regulatory issues is going to be involved.

The specific issues likely to be involved in any power grid development beyond that of simply beefing up the present systems can be summarized as follows.

Authority to Require Participation

Any legislation authorizing a national power grid must deal with whether all electric utilities, regardless or ownership and regardless of size, must be required to participate. Additionally, the question of which agency or agencies should have the authority to make such determinations and to implement them must be raised and met. In general, primary responsibility should be vested in a Federal agency, and preferably one that is already in existence--this obviously points to either the FPC or FEA. As between the two, FPC, as a well-established permanent agency, presumably has more expertise and should probably be preferred. Close and continuing cooperation with state regulatory agencies (something that really does not now exist on a very effective basis) would be essential, but only one agency can have the final word, and that should be the Federal institution.

Rate Regulation

The FPC presently has responsibility for approving rates at which power is sold for resale in interstate commerce. It would seem practical for it to retain that authority and, to the extent that there are additional volumes of electric energy moving in interstate commerce, this would add somewhat to the FPC's burden. For all practical purposes, the interchange rates, under existing practice, have been fixed by the companies with comparatively little involvement by the FPC. Its major involvement has been in the sale of power by relatively large investor-owned utilities to municipal and cooperative distribution systems where disputes have arisen over proper rate levels.

Clearly, there would be an additional dimension of FPC involvement if utilities were required to sell power, rather than being willing sellers and buyers. Criteria that ought to be used by FPC, should it continue to be the rate regulating agency, should reflect such factors as the cost of generation, the detriment or loss of revenue resulting from involuntary transfers, and the need on the part of the selling utility to use its less efficient equipment. Any proposed legislation should undertake to indicate the criteria to be considered and will undoubtedly have many suggestions from utilities for items to be included. This would come even from those who oppose the concept of a national grid.

Involuntary transfers of electric energy from one state to another would inspire controversy and opposition. One of the basic pillars of such a program should be a condition that consumers of all involved states share the benefits of such transfers. Electric utilities will claim that the interchange of power is an exceedingly complex matter and that governmental intervention in their bilateral or multilateral dealings can only serve to further complicate the relationships. There is some merit to the point, but a regulatory agency would be expected to use many of the techniques and methods for facilitating interchanges that have already been established by utilities on a contractual basis rather than impose arbitrary requirements.

Allocation of Capital and Operating Costs

To the extent there is widespread participation by numerous utilities in a power grid or a portion of a national grid, there may well be disputes as to who should pay how much of the cost of construction and of the maintenance and operating costs. Traditionally, this is a subject of negotiations among utilities participating in such ventures, and yet, as in the case of rates where participation is required as distinguished from voluntary, there must be an agency to resolve disputes and to develop acceptable techniques for the allocation of such costs. This is not likely to be an easy or simple exercise but is an essential one if a nonvoluntary grid is to be established.

Technical and Physical Considerations

If the option of a Federally owned and Federally-operated grid is ultimately selected, the designated operating agency will, of necessity, have responsibility for such matters as determining transmission line needs, the voltage and carrying capacity of the lines, safety and design of the lines and accompanying towers, and all other related facilities. If it is not to be a Federal operation but one mandated by law, responsibility for approving certificates for construction of transmission lines must be undertaken by a regulatory agency. Under existing practice, the FPC does not certificate or approve construction of such lines, but it or another designated agency should have such authority given to it if the national grid option selected is through operation under mandate of law rather than direct Federal corporate control.

If the Federal alternative is selected, it must operate in states which will want to have something to say about what happens within their borders. Legislative delegations to the Federal corporation created to operate the grid would probably require the corporation to secure state approvals, with the clear understanding that no state could impose an undue burden on interstate commerce with unrealistic requirements. This might be handled by the use of joint Federal and state hearings and certificate-approving procedures; that concept is already a part of the Federal Power Act and has been since 1935, although it has been very rarely used.[27]

Environmental Regulation

Part of the difficulty facing today's electric utility industry is the requirement that its construction and operation be far more sensitive to environmental concerns than was the case only a decade ago. Adherence to Federal, state, and local environmental regulation is a factor that must be considered in any effort to put the Federal Government into the transmission business in a big way or in requiring the industry to upgrade its activities insofar as regional transfers of electric energy are concerned.

The preeminence of the Federal Environmental Protection Agency may make it possible to limit the potential for dispute and delay at state and local levels. Today's attitudes on protecting the environment are both strong and legitimate. Environmental protection is not a peripheral or frivolous aspect of constructing a national power grid to be relegated to second or third level attention. Should there be Federal legislation authorizing a national power grid, it should certainly deal with the subject of environmental review.

It is possible that a strong and well-defined transmission line network can have a positive environmental impact by reducing the number of new transmission lines that are required. Indeed, one of the factors that ought to be given considerable weight, either by a Federal corporation or by regulators, whichever should be the selected option, is the design and capacity of transmission lines that will militate against the construction of unneeded lines.

Wheeling of Power

One of the more contentious issues has been the question of whether transmission line capacity owned by the investor-owned utilities should be made available for wheeling power on behalf of municipally and cooperatively owned utilities. If there is to be a more effective national power grid, it is going to be necessary to deal with this issue.

Mandating that all lines be treated as common carriers will be an approach especially difficult for the private utilities to undertake. However, the private utilities may find more acceptable national power grid legislation that vests an appropriate agency with the authority to regulate the location and capacity of the transmission lines and to require wheeling of power upon its say-so. Certainly, it should be evident that there can be no effective national power grid if there is not a concomitant obligation to design and operate the interregional lines on a basis that will permit more than a couple of utilities to have access to the carrying capacity of such lines. Here, too, there should be no illusions. This has proven to be a very difficult issue in the past, but should not be permitted to stand in the way of achieving a more efficient national network.

CONCLUSION

The regulatory implications of a national power grid are important and even crucial both to a decision as to whether to move in that direction and in the implementation of a decision to go forward. None of these implications constitutes an insuperable obstacle. This listing of the issues suggests that any assessment of the benefits versus the detriments or the complexity of the problem or the legislative hurdles that must be faced, are fairly good sized. Necessarily, this treatment is cursory but it provides a checklist and an indicator of issues and possible solutions.

■ FOOTNOTES TO CHAPTER 8

1 Breyer and MacAvoy. 1974. *Energy regulation by the Federal Power Commission*. p. 11.

2 Pacific Power and Light Company v. FPC, 184 F.2d 272, D.C. Cir. 1950 and Dunk v. Pennsylvania Public Utility Commission, 1969, 252 A.2d 589, 434 Pa.41, Cert. den., 396 U.S. 839.

3 Federal Power Commission. 1973. *Jurisdiction and regulation of electric, gas and telephone utilities*. Washington, D.C. p. 89.

4 *Electrical World*. May 15, 1975. p. 19.

5 Regional utility commissions are suggested in the report of the Energy Policy Project of the Ford Foundation, 1974. *A time to choose, America's energy future*, Ballinger Publishing Company. p. 340.

6 *The Oregonian*. April 14, 1975. Future of coal-fired plants uncertain. p. A12.

7 Act of August 31, 1974. 78 Stat. 756, P.L. 88-552.

8 For examples, see *The Oregonian*, February 26, 1975. Legislator opposes powerplant. Also see *The Oregonian*, April 14, 1975. Future of coal-fired plants uncertain.

9 Breyer and MacAvoy. 1974. *Energy regulation by the Federal Power Commission*. p. 12.

10 Florida Power Corporation v. FPC. 425 F.2d 1196(1970 and Northeast Power Company v. FPC. F.2d 258(1965). See also Ottertail Power Company v. United States. 973. 410 US 366 (1973) 97 PUR 3d 209.

11 Breyer and MacAvoy. 1974. *Energy regulation by the Federal Power Commission*. p. 115.

12 Ottertail Power Copmany v. United States. 410 US 366, at p. 375.

13 Federal Power Commission. 1973. *Federal and state commission jurisdiction and regulation of electric, gas, and telephone utilities*. p. 94.

14 Research has recently been initiated by EPRI in this last category.

15 This is the situation with the intertie between Los Angeles and the Four Corners-area powerplants, for example.

16 Breyer and MacAvoy. 1974. *Energy regulation by the Federal Power Commission*. p. 116.

17 FPC. Dockets No. RM74-22, E-8589, E-8550, et al.

18 Vertical mergers, or integration, refers to mergers between companies performing different steps of a process (e.g., generation, transmission, and distribution). Horizontal integration refers to mergers between companies performing the same function (such as generation) or functions.

19 Leonard W. Weiss. 1975. Antitrust in the electric power industry. *Promoting competition in regulated markets*. p. 138. Weiss was referring specifically to the hypothetical situation where transmission companies would be treated as common carriers.

20 Ibid.

21 U.S. Nuclear Regulatory Commission. 1975. *Coordination, competition, and reguation in the electric power industry*. p. 43. (NUREG-75/061).

22 Energy Policy Project of the Ford Foundation. 1974. *A time to choose*. p. 340.

23 Breyer and MacAvoy. 1974. *Energy regulation by the Federal Power Commission*. p. 109.

24 FPC Dockets No. RM74-22, E-8589, E-8550, et al.

25 Breyer and MacAvoy. 1974. *Energy regulation by the Federal Power Commission*. p. 118.

26 Hughes, William R. *Scale frontiers in electric power*. p. 59.

27 Federal Power Act, Section 209(b), 16 U.S.C. 824h.

Chapter 9
ADDITIONAL STUDIES

It was expected that the limited scope of this study of such a far-reaching subject area would lead to suggestions for additional study. We believe the following studies would be useful to further analysis of the desirability and feasibility of a national power grid. Even if a national grid, in the sense of discrete facilities overlaying the existing electric networks of the nation, is not feasible, most of these studies should prove beneficial to the planning and operations of the country's electric utility systems.

LOAD DIVERSITY

By all means, the ongoing studies being done by the Edison Electric Institute should be continued.

Detailed studies, region by region, of how diversity is now being used and the relationships of planned maintenance scheduling and diversity, would be valuable to future studies of specific coordinated operations.

A useful tool for planning possible use of load diversity would be a probabilistic analysis technique for forecasting short-term, seasonal, and time-zone diversities. This would be a needed refinement over present methods of using historical diversity ratios or trending historical patterns. The mathematical model for such an analysis technique would need to take into account interrelated factors, including the influences on load diversity of weather patterns, geographic conditions, load growth rates and patterns, conservation and load management programs, general economic conditions, and the effect of governmental and regulatory policy and actions.

Additional study is needed to determine more accurately demand-price elasticities and the effects of rate structures on demand, quantity demanded, load shapes over time, and load diversity. Present studies of demand and elasticities should be continued. An expanded research program on demand for electricity and other energy sources as it is affected by price levels and structures is needed to provide a basis for decisions on capital investments, such as the strengthening of interregional transmission grids. Price as a load management tool may be heavily influential on diversity.

RESERVES

The development of analysis techniques, practicable on existing computers, for examining parameters affecting reserve requirements on systems as large as the entire United States would be valuable.

Studies should be made to determine how reliable electric systems need to be and public attitudes in this regard. The studies should include relationships of reliability and cost. Also, the practicality of establishing and implementing different reliability standards for different classes of customers should be examined. Regulatory and legal ramifications would have to be considered, and legislation may be needed, before implementing any findings from such studies.

Certainly the ongoing efforts to improve the reliability of generating facilities should be intensified because machine reliability is a major factor in determining overall reserve requirements.

TRANSMISSION

Much is being done by the Electric Power Research Institute (EPRI) and the Energy Research and Development Administration (ERDA) toward identifying and undertaking studies leading to improvements in transmission that may broadly benefit the entire electric utility industry. However, some specific studies of a narrower scope are suggested by this study.

- There seems to be enough potential merit to justify a more definitive study of an ERCOT-SPP interconnection. Such a study should include analysis of power flow, system stability, reserve requirements, diversity, an overall benefit/cost study, and an allocation of net benefits, if any, among the entities involved.
- A detailed study of a direct current (dc) high-capacity transmission line between WSCC and MARCA might prove fruitful based on our updated benefit/cost analysis of this potential interconnection. The study should take into account alternatives including additional north-south lines within WSCC and within MARCA (including Manitoba) that might have high benefit/cost ratios and preempt benefits of a WSCC-MARCA tie.
- Studies of alternative methods of providing steam powerplant condenser cooling in areas that have abundant fuel resources, but scarce water supplies, could expedite development of needed energy resources. If such resources are developed with generating plants located near the fuel sources, major inter-regional transmission would be required.

- Studies of the impact on reliability by outages of substations of various types and of transmission lines of different specifications would provide information needed to augment generation forced outage rates in determining system reliability standards.

ECONOMIC CONSIDERATIONS

Research completed on powerpooling has addressed the question of optimum size of integrated system. This research into industry organization and scale economies should be extended to determining system size and the efficient mixes of equipment needed to serve loads of different characteristics. All of these studies could be a foundation for future development (rationalization) of the electric utility industry.

Regardless of the load growth that occurs, the bulk electric power industry will need capital on a large scale. There have been numerous instances in the past 5 years of utilities not being capable of raising adequate funds at satisfactory interest rates to maintain planned service levels and build for forecast demand and not have to ask for permission to raise rates. Alternative methods of financing and different methods of organizing the industrial structure to facilitate the financing are needed.

Pricing is one of the focal points of economics. Currently underway is an array of studies and demonstration projects on different rate structures and how their employ might affect demand for electricity. These studies should be continued. However, we believe that the studies do not go deeply enough into matters of hour-by-hour price elasticity, the interrelationships of price-structures and demand over a time period, prices of alternative energy forms, and the many other influences on demand. Once demand behavior is known and can be predicted with satisfactory accuracy, industry planning can be greatly more precise. When this is possible, few problems will be encountered with industry performance, service levels, and financing.

Knowing price, income, demand, and alternate energy interrelationships and those of other influential factors such as weather and geographic location will also provide the raw materials to predict changes in the annual peak demand--possibly the occurrence of the peak and its magnitude can be controlled.

In this study we found that the marginal benefit to individual electricity consumers of rather large changes in the industry's operating reserves would probably not exceed a 5-percent saving in annual power costs. More comprehensive studies of the benefits that may be derived from other major changes in the energy sectors are needed. For example, the research for new nonpetroleum energy sources should be expanded and continued. So should all of the research projects on load management and cross price elasticity for alternative energy sources.

Studies are needed of costs that are presently not easily quantified, such as the current use of scarce resources, obviating their subsequent employment in alternative uses with increasing returns. External costs and benefits, such as net costs of water, air, and noise pollution and the net benefits of high reliability and availability of power supply, must be identified. Mechanisms developed for their internalization will be needed before fully satisfactory economic evaluation can be made of the industry and changes in it.

A very careful study of the costs and the benefits of the regulatory process is needed. Preferably, this study would be detailed enough to identify the effectiveness of regulatory agencies and their individual regulatory functions. All of this is basic to positive change in the regulatory process.

Results of studies of the investment and operating economies associated with scale of plant and load characteristics and possible benefits of powerparks are needed as soon as possible to provide industry planning bases.

REGULATORY CONSIDERATIONS

The entire regulatory process in the U.S. needs to be studied in great detail for jurisdictional overlaps and functional duplications we have just touched on in this study. Once these redundancies are identified, institutional changes aimed at more efficient overall regulation should be instituted.

The issues related to resource depletion in one area, and "exportation" of environmental pollution from the energy-consuming area to the production area, the "coal by wire" question, have far-reaching implications. These must be positively addressed before a fully integrated national transmission grid can be specified and built.

Although economic pressures currently provide strong incentives for industry cooperation, certain interfirm actions could yield benefits to the energy-consuming public. Authority to require coordinated maintenance, shared reserves, and economy energy interchange needs definition. Furthermore, the whole field of interutility relationships must be monitored to prevent abuse of the public interest. This monitoring must be functionally defined and delineated, and regulatory responsibility assigned.

The energy industry is closely interrelated because of the interchangability or substitutability of energy forms, within certain constraints. The amassing of controls over various energy forms by single firms or small groups of firms must be studied for its impact on the public. It is especially important in light of antitrust implications and the demand-price relationships of the energy forms.

A corollary of this is the relatively independent activities of Federal regulatory agencies having separate jurisdictions over parts of the energy sector of the economy and the fact that these regulatory activities are not coordinated. Furthermore, much of the energy sector is not subject to direct regulatory monitoring. The relative pricing among these interchangeable energy sources has a continuing disequilibrating influence on the nation's economy. A comprehensive study is needed of ways to regulate the various energy sector subsets as they influence each other.

In light of the way regulatory bodies are normally staffed, it is desirable that studies be undertaken to define staffing and staff-training alternatives to avoid instances of regulatory commissions' submission to the interests of the regulated.

Fundamental to all studies suggested here is the need for dramatic changes from current conditions in the collection of data on the industry, in its processing, in its general availability, and in the methods of public access. Studies on a broad-scale basis of data collection and storage, avoidance of duplication of effort, and constraints on research through data-access restrictions are needed.

Accountability standards must be established for all regulatory agencies. These standards are needed for accountability of budgeted funds and for the exercise of authority. A method of determining regulatory adherence to the standards in the public interest is needed.

Regulation of rates is fundamental as noted in economic considerations above. Considerably more work is needed in the field of rates, their institution and control, and their influence on demand and amounts of energy demanded. Particularly important are studies related to regulation of rates and the costs of that regulatory activity.

The costs of regulation are functions of the objectives of the various regulatory agencies. It would be beneficial in legislative decisions related to regulation in the energy sector to have identified the relative costs of regulation of different kinds in the different energy subsectors.

It has become important, in light of the creation of large powerpools operating in several states, that state regulatory agencies cooperate with each other or that consideration be given to regional or overall Federal regulation. Studies of alternative approaches to achieving equitable regulation in the various states are needed to provide a basis for rationalization of the present differences from state to state. It will be important in such studies to take into account important regional differences influencing power system characteristics.

BIBLIOGRAPHY

Asbury, C. E. July/August 1975. Weather load model for electric demand and energy forecasting. *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-94, No. 4. Paper T 73 453-8.

Auge', J., Berquognoux, J., Dodu, J. C., and Douqet, J. *Probabilistic study of a transmission system interconnection (Peru Model)*. Electricite' de France, France.

Ayoub, A. K., and Patton, A. D. April 1975. A frequency and duration method for generating system reliability evaluation. *IEEE Transaction on Power Apparatus and Systems*. Paper F 75 42.

Baldwin, C. J. April 1966. Reserve sharing is primary benefit from power pooling. *Power Engineering*. pp. 59-61.

———. March 1969. Probability calculation of generation reserves. *Westinghouse Engineer*.

Berline, E., Cicchetti, C. J., and Gillen, W. J. 1974. *Perspective on power: a study of the regulation and pricing of electric power*. Cambridge, Massachusetts: Ballinger Publishing Company.

Billington, R. *Power system reliability evaluation*. New York, New York: Gordon and Breach, Science Publishers.

Billington, R., Ringlee, R. J., and Wood, A. J. *Power system reliability calculations*. Cambridge, Massachusetts: The MIT Press.

Bonneville Power Administration. 1958. *The Northwest Power Pool*. Branch of System Operations and Power Resources. Portland, Oregon: U.S. Department of the Interior.

———. February 1960. *Study of a high voltage electrical interconnection between the Pacific Northwest and California*. Portland, Oregon.

———. August 6, 1973. *Proposal for 1,100 kV transmission line prototype*. Branch of System Engineering. Portland, Oregon.

———. April 1975. *Pacific intertie - the large-scale sharing of electric resources*. Portland, Oregon: U.S. Department of the Interior.

———. July 1, 1975. *Firm, secondary, and surplus hydropower.* Portland, Oregon: U.S. Department of the Interior.

Breyer, Stephen G., and MacAvoy, Paul W. 1974. *Energy regulation by the Federal Power Commission.* Washington, D.C.: The Brookings Institution.

The Bureau of National Affairs, Inc. July 17, 1975. Electric power: head of research group sees need for double production every 10 years. *Energy user's report.* Washington, D.C.

Casazza, J. A., and Hoffman, C. H. 1968. Relationship between pool size, unit size, and transmission requirements. *International Conference on Large High Tension Electric Systems.*

Dhrymes, Phoebus J., and Kurz, Mordecai. July 1974. Technology and scale in electricity generation. *Econometrica,* vol. 32, pp. 287-315.

Dillard, J. K., and Baldwin, L. J. 1973. The impact of pooling on power system planning. *Electrical Engineering,* pp. 442-449.

Dunk v. Pennsylvania Public Utility Commission, 1969, 252 A.2d 589, 434 Pa.41, Cert. den., 369 US 839.

East Central Area Reliability Coordination Agreement. April 1975. *Conceptual planning projections: a report by ECAR bulk power members to the Federal Power Commission pursuant to docket R-362, order 383-3,* vol. V.

———. April 1975. *Load projections and resource planning: a report by ECAR bulk power members to the Federal Power Commission pursuant to docket R-362, order 383-3,* vol. I.

———. April 1975. *System performance and transmission planning: a report by ECAR bulk power members to the Federal Power Commission pursuant to docket R-362, order 383-3,* vol. II.

Edison Electric Institute. May 1963. *Report on the status of interconnections and pooling of electric utility systems in the United States.* New York: EEI.

———. May 1964. *Data preparation for the Edison Electric Institute load diversity study.* New York: EEI.

———. May 1969. *Instructions for data preparation for the Edison Electric Institute load diversity study.* New York: EEI.

———. 1970. *EEI load diversity study: time zone load study*. New York: EEI.

———. 1971. *EEI load diversity study: time zone load study*. New York: EEI.

———. 1973. *Publications and service materials*. New York: EEI.

———. June 12, 1974. *Position of the Edison Electric Institute on the need for a national grid*. New York: EEI.

———. 1974. *Ten-year report on load diversity based on 1962-1971 load data*. New York: EEI.

———. June 1975. *Advance release of data for the statistical year book of the electric utility industry - year 1974*. New York: EEI, Economics and Statistical Department. p. 7.

———. 1975. *Economic growth in the future*. New York: EEI.

Electrical Week. May 19, 1975. FEA, fearing power crunch, studies prospects of an electric economy.

———. June 16, 1975. Zarb's rate-design goal: shave $49 billion off utility expansion by 1985.

———. July 7, 1975. Transmission incident bumps 2,000 MW, causing no more than a blink. p. 5.

———. July 28, 1975. Four Texas municipals, Brazos Co-op plan joint generating stations. p. 3.

———. August 11, 1975. NERC urges revamped contingency planning to meet power supply threat.

———. September 15, 1975. EEI's big economic growth study appears to score initial White House success. p. 4.

———. September 22, 1975. Westinghouse warns: don't let low summer peak spur new round of cutbacks. p. 6.

Electrical World. March 15, 1975. 1975 annual statistical report.

———. May 15, 1975. Delaware P&L continues its five-year effort to close the final link.... p. 19.

———. May 15, 1975. Slump in winter peak growth persists. pp. 62-63.

———. June 1, 1975. EEI takes middle road in debate on growth patterns. p. 25.

———. June 1, 1975. NERC sees low generation reserves. p. 62.

———. June 1, 1975. Standard rates in PJM area? p. 28.

———. July 1, 1975. Texas, the last holdout, yield to state regulation. p. 23.

———. July 1, 1975. World news beat: load management, FEA administrator Frank Zarb sets goal of annual kWhr growth. . . .

———. August 15, 1975. EPRI analyzes biological impact. pp. 46-47.

———. August 15, 1975. Four municipals and a co-op in Texas join to build future G&T projects. p. 17.

Electric Light and Power. July 21, 1975. The top 100 electric utilities--1974--A year of zero growth. pp. 7-11.

Electric Power Research Institute. July 1974. *Fossil fuel and advanced systems division*. Palo Alto, California.

Electric Reliability Council of Texas. April 1975. *Response to Federal Power Commission, order No. 383-3, docket No. R-362*.

Electric Utilities Industry Council. Research and Development Goals Task Force. June 1971. *Electric utilities industry research and development goals through the year 2000*.

Energy Policy Project of the Ford Foundation. 1974. *A time to choose: America's energy future*. Cambridge, Massachusetts: Ballinger Publishing Company.

Engineering Executives. February 1, 1941. Report to Mr. Leland Olds, Chairman, Federal Power Commission pertaining to the National Defense Network.

Engineering News Record. August 21, 1975. Utilities hedge on nuclear plans; coal plant prospects brighten. p. 10.

Falk, A. K. The effects of availability upon installed reserve requirements. *IEEE Transactions on Power Apparatus and Systems*. vol. PAS 85, pp. 1135-1144, paper 31 TP 66-8.

Federal Energy Administration. March 1975. *A report on improving the productivity of electric powerplants*. Washington, D.C.: U.S. Government Printing Office.

———. August 1, 1975. *Utilities conservation action now*. Office of Energy Conservation. Washington, D.C.

Federal Power Commission. Dockets No. RM74-22, E-8589, E-8550, et al.

———. October 1964. *National power survey*. Washington, D.C.: Government Printing Office.

———. 1965. *Glossary of important power and rate terms, abbreviations, and units of measurement*. Prepared under direction of Inter-agency Committee on Water Resources.

———. 1968. *Hydroelectric power evaluation*. Washington, D.C. p. 35.

———. 1969. *Hydroelectric power evaluation supplement No. 1*. Washington, D.C. p. 38.

———. December 1971. *The 1970 national power survey*. Washington, D.C.

———. October 1972. *Study of proposed interconnection between Electric Reliability Council of Texas and Southwest Power Pool*. Bureau of Power staff report. Fort Worth, Texas: FPC Regional Office.

———. 1973. *Federal and state commission jurisdiction and regulation of electric, gas, and telephone utilities*. Washington, D.C.

———. March 12, 1974. *Federal Power Commission reports on electric transmission line mileage data in fiscal 1974*. News release. Washington, D.C.

———. March 19, 1974. *Federal Power Commission issues new edition of report on federal, state regulation of utilities*. News Release No. 20136.

———. August 1974. New England Power Pool Participant et al., Appalachian Power Company, et al., Dockets No. RM74-2, E-8550 et al. Order permitting withdrawal of petition for emergency relief (Docket No. E-8589), and accepting rate schedules, permitting withdrawal of rate schedules, disposing of procedural matters and terminating proceedings. Washington, D.C.

———. November 1974. *Federal Power Commission releases staff report on bulk power supply stability*. Washington, D.C.

———. November 1974. Order No. 520: order amending part 32 of the regulations under the Federal Power Act; applications for Commission emergency authorization pursuant to section 202(c) of the Act. Washington, D.C.

———. December 1974. Techncial Advisory Committee on Finance. *National power survey: the financial outlook for the electric power industry*. Report and recommendations. Washington, D.C.

———. January 1975. Order No. 520-A: order amending part of the regulations under the Federal Power Act; and denying applications for rehearing and reconsideration of order issuing regulations. Washington, D.C.

———. July 4, 1975. Bulk power load and supply information, reported April 1, 1975 by the Regional Reliability Councils under Docket No. R-362 (Order 383-3). News Release. Washington, D.C.

———. May 1975. *Electric generating plant availability*. Bureau of Power Staff Report.

———. June 1975. Federal Power Commission issues staff summary of electric utility expansion plans for 1975-1984. News Release. Washington, D.C.

Florida Power Corporation v. FPC. 425 F.2d 1196(1970).

Freeman, S. David. 1974. *Energy: the new era*. New York: Random House.

Friedlander. May 1975. Energy's hazy future. *Spectrum*. p. 40.

Galatin, Malcolm. 1968. *Economies of scale: technological change in thermal power generation*. Amsterdam: North Holland Publishing Company.

Garver, L. L. Effective load carrying capability of generating units. *IEEE Transactions on Power Apparatus and Systems*, vol. PAS 85, pp. 910-919, paper 30 TP 66-5.

———. Adjusting maintenance schedules to levelize risk. *IEEE Transactions on Power Apparatus and Systems*, vol. PAS 91, pp. 2,057-2,063, paper T 72 154-8.

The General Council, Working Staff Task Force. April 1975. *Working draft paper memorandum re: H. R. 5048-S. 1208 (national grid) and related energy proposals.*

Greene, William H. August 1975. *Interfirm competition and scale economies in steam-electric power generation.* University of Wisconsin.

Handy Whitman Index of Public Utility Construction. 1974. Baltimore, Maryland: Whitman, Requardt and Associates.

Hill, Bob. August 14, 1975. FEA conversion orders blasted by electric companies. *Public Utilities Fortnightly.* pp. 13-14.

Holme, K., and Associates, Consultants. January 1970. *Coal resources for electric generation.* Washington, D.C.

Hughes, William R. Scale frontiers in electric power. Chapter 3 of *Technological change in regulated industries.* Capron, William M., editor, Brookings Institution, Washington, D.C.

Humpage, W. D. August 1973. Structure for multiscale power system dynamic analysis methods. *IEEE Proceedings* 120: 853-9.

Irisarri, G., and El-Abiad, A. H. April 1975. Reliability evaluation for application in generation planning. *IEEE Transactions on Power Apparatus and Systems.* Paper A 75 429-1.

James, Richard D. September 17, 1975. Pacific G&E get a rate increase of $213.4 million. *Wall Street Journal*, vol. XCIII, no. 55.

Johnson, W. L., and Mulligan, R. E. January 15, 1974. System watches 100 plus interchanges. *Electrical World.* p. 80.

Kaufman, Alvin. 1975. *Reliability criteria - a cost-benefit analysis.* Albany, N.Y.: New York Public Service Commission, Office of Economic Research.

Kerenyi, A. O., Ronkay, F., Peto, J., Szendy, K., and Hadik, Z. June 1968. Effect of increasing the generating unit size on system interconnection tie lines. Paper read at International Conference on Large High Tension Electric Systems.

Kirchmayer, L. K., Mellor, A. G., O'Mara, J. F., and Stevenson, J. R. August 1955. An investigation of the economic size of steam-electric generating units. *AIEE Transactions*, vol. 74, part III, pp. 600-14.

Kroeger, Carroll V., and Rawls, James R. August 14, 1975. Managerial attitudes toward government roles in electricity and gas. *Public Utilities Fortnightly*. pp. 22-28.

LaForest, James J., and Truax, Charles J. June 1975. Energy transmission...what lies ahead. *Electric Forum*. p. 3.

Landgren, G. L., and Anderson, S. W. Simultaneous power interchange capability analysis. *IEEE Transactions on Power Apparatus and Systems*. Paper T 73 075-9.

Landsberg, Hans H., and Schurr, Sam H. 1968. *Energy in the United States*. New York: Random House.

Mabuce, Estel M., Wilks, Richard L., and Bonerman, Stuart B. Generation reserve requirements - sensitivity to variations in system parameters. *IEEE paper C72 481-0*, presented at Power Engineering Society summer meeting, 1972.

McDaniel, G. H., Gabrielle, A. F. July 1965. Load diversity--its role in power system utilization. *IEEE Journal*. pp. 626-635.

Madison Gas & Electric Company, Re Spur 4th (Wisonsin 1974).

Malek, N. G. October 1973. Trajectory sensitive design of load-frequency control system. *IEEE Proceedings* 120: 1273-7.

Matthews, Walter J. June 11-12, 1975. Impact of load management on regional reliability councils and power pools. *Proceedings of the Conference on the Challenge of Load Management - A convergence of diverse interests*. Washington, D.C.: The Federal Energy Administration, Office of Utilities Programs. p. 54.

Meeks, James E. 1972. Concentration in the electric power industry: the impact of antitrust policy. *Columbia Law Review*. p. 64-130.

Mid-America Interpool Network. April 1975. *MAIN's 1975 reply to appendix A-1 of order No. 383-3.*

Mid-Continent Area Power Pool (MAPP), Missouri Basin Systems Group (MBSG), and Southwest Power Pool (SPP). December 1973. *Report of the western United States-central United States study of transmission interconnection*.

Mid-Continent Area Reliability Coordination Agreement (MARCA). November 1969. *Mid-Continent Area Reliability Coordination Agreement: system operating standards*.

———. April 1975. *A report by MARCA to the Federal Power Commission pursuant to FPC docket no. R-362, appendix A-1.*

———. April 1975. *A report by MARCA to the Federal Power Commission pursuant to FPC docket no. R-362, attachment no. 1 (containing smaller system information).*

Moses, M. A. August 1973. *An approach to the power shortage problem: optimal allocation of existing excess reserves through interregional transmission*. Springfield, Virginia: National Technical Information Service, U.S. Department of Commerce.

Missouri Basin Systems Group: Planning Committee. July 1970. *Western intersystem diversity and energy program: a hydrothermal reconnaissance study*.

Molony, Mike. May 1975. Year of the grid. *Rural Electrification*. p. 16.

Myhra, David. August 14, 1975. What others think. *Public Utilities Fortnightly*. pp. 41-44.

Nagel, T. J. January 1972. The national grid - a misconception. *Utilities Fortnightly*, pp. 31-38.

Nassikas, J. K. May 1975. *The role of electric power in meeting future energy needs*. Washington, D.C.: FPC.

National Electric Reliability Council. July 1973. *An assessment of the proposed National Power Grid Act*. Princeton, New Jersey.

———. December 1973. *Multiregional transmission study of power transfer capabilities of the 1973 bulk power interconnected network in NERC*. Princeton, New Jersey.

———. October 1974. *Multiregional transmission study of power transfer capabilities of the 1978 bulk power interconnected network*. Princeton, New Jersey.

———. October 1974. *Reveiw of overall adequacy and reliability of the North American bulk power systems*. Interregional Review Subcommittee of the Technical Advisory Committee. A report by the National Electric Reliability Council. Princeton, New Jersey.

———. March 1975. *A current view of the view of the impact of postponements and cancellations on future electric bulk power supply in the United States*. Princeton, New Jersey.

———. April 1975. *National Electric Reliability Council 1974 annual report with reports from its regional councils*. Princeton, New Jersey.

———. July 1975. *Estimated fossil fuel requirements, projected generating capacity, and electric energy production for the electric utility industry (Contiguous U.S.), 1975-1984*. Princeton, New Jersey.

———. July 1975. *Review of overall reliability and adequacy of the North American bulk power systems*. (Fifth annual review.) A report by the Interregional Review Subcommittee of the Technical Advisory Committee. Princeton, New Jersey.

Nelson, Paul A. 1974. The effect of market structure on efficiency in the electric power industry. Ph. D. Thesis-Economics, University of Wisconsin, Madison, Wisconsin.

Nerlove, Marc. 1963. Returns to scale in electricity supply, in Carl Christ, et al., *Measurement in economics*. Palo Alto, California: Stanford University Press.

New England Power Pool. September 1971. *New England Power pool Agreement*.

Northeast Power Compny v. FPC. F.2d 258(1965).

Northeastern Reliability Council. July 1975. *Government regulations: transmission*. NERC. pp. 7-8.

Nuclear Regulatory Commission. 1974. *The nuclear industry - 1974*. WASH 1174-74. Washington, D.C.: NRC.

Ottertail Power Company v. United States. 410 US 366, at p. 375. See also 97 PUR 3d 209.

Pacific Power and Light Company v. FPC, 184F.2d, DC. Cir. 1950.

Pang, C. K., and Wood, A. J. Multi-area generation system reliability calculations. *IEEE Transactions on Power Apparatus and Systems*. Paper T 74 342-2.

———. May 1975. Multi-area power system reliability calculations: extensions and examples. *IEEE Transactions on Power Apparatus and Systems*. Paper A 75-5 35.

Paris, L., and Valtorta, M. June 1968. Planning the installation of large units in interconnected systems: relevant parameters and their relative influence. *Proceedings from International Conference on Large High Tension Electric Systems*.

Patton, A. D., and Stasinos, A. July/August 1975. Variance and approximate confidence limits on LOLP for a single-area system. *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-94, Paper T75 075.

The Pennsylvania-New Jersey-Maryland Interconnection. November 1974. *The Pennsylvania-New Jersey-Maryland interconnection operating principles and standards*, 3rd revision.

Peterson, W. S. February 1, 1941. Discussion of progress report by engineering executives on interconnecting line system.

Peterson, W. S. to Scattergood, E. F. February 1, 1941. Memorandum discussing report by engineering executives.

Phillips, Almarin, ed. 1975. *Promoting competition in regulated markets*. Washington, D.C.: The Brookings Institution.

Phillips, Jr., Charles F. 1969. *The economics of regulation*. Homewood: Richard D. Irwin, Inc.

Portland Oregonian. April 14, 1975. Future of coal-fired plants uncertain. p. A12. Portland, Oregon.

———. February 26, 1975. Legislator opposes powerplant. Portland, Oregon.

Public Law 88-552. August 31, 1974. 78 Stat. 756.

Public Power Weekly Newsletter. August 15, 1975. Direct current tie in Nebraska will link eastern and western grids. p. 1. Washington, D.C.: American Public Power Association.

———. August 15, 1975. Electric heat outpaced gas in 1974 new homes. Washington, D.C.: American Public Power Association.

Public Utilities Fortnightly. July 31, 1975. Coal company sought by utilities: its fate still uncertain. Washington, D.C.: Public Utilities Reports, Inc.

———. August 14, 1975. FEA conversion orders blasted by electric companies. Washington, D.C.: Public Utilities Reports, Inc.

———. July 31, 1975. FPC says electric growth will slow down. p. 13. Washington, D.C.: Public Utilities Reports, Inc.

Reading, H. G. September 6, 1973. Overhead lines for the supergrid. *Electronics and Power*, 19: 352-6.

Reeder. H. C. March 1975. *Water supply and treatment facilities, city of Colorado Springs R.D. Nixon power plant.* Appendix A. Denver, Colorado: CH2M HILL, Inc.

Re Madison Gas and Electric Company. August 8, 1974. In *Public Utilities Reports 5 PUR 4th.* Washington, D.C.: Public Utilities Reports, Inc.

Res, S. T. Y., and Schweppe, F. C. September 1973. Distance measures and coherency recognition for transient stability equivalents. *IEEE Transactions on Power Apparatus and Systems*, 92: 1550-7.

Ringlee, R. J., and Beck, J. W. December 1974. *An assessment of policies and technical factors affecting the degree of interconnection of electric utilities in the U.S.* Schenectady, New York: Power Technologies, Inc.

Roddis, Louis H. Remarks to American Public Power Association Power Supply Planning Committee as quoted in *Electrical Week*, February 3, 1975, p. 5.

Rosenberg, William G. February 27, 1975. Kilowatts and capital: the real energy crisis. *Public Utilities Fortnightly*. p. 26.

Savage, N., and Wofsy, L. A. January 1975. Peak week excess-load-probability. IEEE PES Winter Meeting; Paper No. C75019-5.

Schuck, Peter H. September 1975. Why regulation fails. *Harper's*, vol. 251, pp. 16-29.

The Science and Public Policy Program. May 1975. *Energy alternatives: a comparative analysis*. University of Oklahoma, Norman, Oklahoma.

Scott, D. N. et al. December 1973. Power loss detector for Pacific HVDC intertie. *Control Engineering*, 20: 64-65.

Sewell, W. R. Derrick. May 1963. Regional interties and national supergrids. *Water Power*, pp. 211-215.

Sheehan, Robert G. October 4, 1973. The energy and generation scene: dreams, realities, and the future. Pullman, Washington: Washington State University Thermal Power Conference. Conference paper.

Shipley, R. B., Patton, A. D., and Denison, J. S. Power reliability cost vs worth. *IEEE Transactions on Power Apparatus and Systems*, vol. PAS-91, pp. 2204-2212.

Southeastern Electric Reliability Council. April 1972. *Coordinated bulk power supply program, 1972-1981*. Report to the Federal Power Commission and cognizant state public service commissions.

Sporn, P. *The U.S. national power survey - its organization and conclusions - a critique*. CIGRE paper 313.

———. April 14, 1975. *Energy in an age of limited availability and delimited applicability*. Delivered at Manhattan College, New York. New York: Kuhn, Loeb & Co.

Steinberg, M. J., and Cook, V. M. April 1956. Evaluation of unit capacity additions. *AIEE Transactions*, pp. 169-179.

Thomas, E. L., Holmes, J. G., and Schonhoff, C. C. April 1971. Experience with large supercritical units. *Combustion*.

Tinkleman, Michael. December 1974. Maintaining electric power through the oil crisis. *The Journal of Accountancy*, p. 47.

Thompson, Wayne. August 24, 1975. Northwest power shortage will equal four Bonnevilles. *The Sunday Oregonian*. Portland, Oregon, p. F1.

United States Atomic Energy Commission. December 1973. *The nation's energy future*. Washington, D.C.: U.S. Government Printing Office.

United States Department of the Interior. July 1, 1975. *The need for a national system of transportation and utility corridors*. Washington, D.C.

———. December 15, 1961. *Pacific Northwest-Pacific Southwest extra-high-voltage common carrier interconnection*. Special Task Force Report.

———. Region II. January 1949. *Preliminary report on an interconnection between the power systems of the Bonneville Power Administration and the Central Valley project*. Sacramento, California.

———. Bureau of Reclamation. February 1968. *Transmission study 190. Steering Committee Report*. Washington, D.C.

United States Nuclear Regulatory Commission. June 1975. *Coordination, competition, and regulation in the electric utility industry*. Economic Analysis Section, Office of Antitrust and Indemnity. NUREG-75/061.

United States Senate, Committee on Interior and Insular Affairs. March 1974. *Electric utility power issues: the national fuels and energy policy study*. Washington, D.C.: U.S. Government Printing Office.

United States Government Manual. 1974-1975. Washington, D.C.: General Services Administration.

Vassell, G.S., and Tibberts, N. *Analysis of generating-capacity reserve requirements for interconnected power systems*. pp. 638-649, paper 71 TP 92-PWR.

Vogtle, A. W. March 26, 1959. Coal by wire. *Public Utilities Fortnightly*.

Weiss, Leonard W. 1975. Anti-trust in the electric power industry. In Phillips, L. W., ed., *Promoting competition in regulated markets*. Washington, D.C.: The Brookings Institution.

Western systems Coordinating Council. April 1975. *Reliability and adequacy of electric service*. Reply to Federal Power Commisson, Docket R-362, Order No. 383-3.

Western Systems Coordinating Council (WSCC), Mid-Continent Area Power Planners (MAPP), Mid-American Inter-pool Network (MAIN), and East Central Area Reliability Agreement (ECAR). July 1969. *An appraisal of transmission study 190*.

Western Systems Coordinating Council. April 1975. *Reliability and adequacy of electric service*. Reply to Federal Power Commission, Docket R-362, Order No. 383-3..

Zinder, H. & Associates, Inc. September 1960. *California-Pacific Northwest interconnection stage I progress report*. Seattle.

———. September 1970. *A study of the electric power situation in New England, 1970-1990*. The New England Regional Commission.

———. January 1971. *California-Pacific Northwest interconnection stage II report*. Seattle.

GLOSSARY OF ABBREVIATIONS AND DEFINITIONS

ABBREVIATIONS

alternating current	ac	magnetohydrodynamics	MHD
barrels	bbls	mean sea level	Msl
barrels per day	bbl/d	megavolt ampere	MVA
British thermal units	Btu	megawatt	MW
cents	¢	megawatt-hours	MWh
cubic centimeters	cm^3	million cubic feet	MMcf
cubic feet	cf	nitrogen oxides	NO_x
degrees Fahrenheit	°F	parts per million	ppm
direct current	dc	percent	%
electrogasdynamics	EGD	pound	lb
extra high voltage	EHV	pound per hour	lb/hr
gallons	gal	pounds per square inch	psi
gallons per minute	gal/min	pounds per square inch absolute	psia
gigawatt	GW	research and development	R&D
gram	g	reserve to production	R/P
Hertz	Hz	revolutions per minute	r/min
kilogram	kg	standard cubic feet	scf
kilovolt	kV	standard cubic feet per day	scfd
kilovolt-ampere	kVA	sulphur dioxide	SO_2
kilowatt	kW	thousand cubic feet	Mcf
kilowatt-hours	kWh	thousand cubic feet per day	Mcfd
liquefied natural gas	LNG	ultra high voltage	UHV

DEFINITIONS

Alternating Current (ac) – An electric current that reverses its direction of flow periodically (see **Frequency**) as contrasted to direct current.

Ambient Temperature – Temperature of the surrounding cooling medium, such as gas or liquid, which comes into contact with the heated parts of the apparatus.

Anadromous Fish – Fish, such as salmon, which ascend rivers from the sea at certain seasons to spawn.

Area Control Error – A measure of the prevailing area generation error, or the amount by which an area's net interchange with other systems deviates from the desired level.

Asynchronous – Describing two or more electric systems operating at different frequencies of alternating current.

Availability Factor – The ratio of the time a machine or equipment is ready for or in service to the total time interval under consideration.

Backbone Transmission System - The principal portion of a transmission system to which other lines connect.

Back-to-Back dc - Using direct current (dc) converters to send power from one alternating current (ac) system, converted to dc, and then converting back to ac for the receiving system; this ac/dc/ac application eliminates the need to match frequencies of the two ac systems connected--the two ac systems need not operate in synchronism.

Backup - Reserve generating capacity of a power system.

Baseload - The minimum load over a given period of time.

Baseload Power or Baseload Generation - Those generating resources used to supply power and energy for the lower part of the load cycle, generally up to or slightly above the minimum load demand.

Bipolar - Having two electric potentials or opposite polarity (positive and negative), here in reference to direct current (dc) transmission as ±450 kV; bipolar transmission uses electric conductors for both current paths and does not use the earth as conductor for the return path.

Breeder Reactor - A nuclear reactor capable of producing more nuclear fuel than it consumes.

British Thermal Unit (Btu) - British thermal unit. A measure of heat energy. The quantity of heat energy required to raise the temperature of 1 pound of water 1 degree Fahrenheit, at sea level.

Bulk Delivery Point - A substation which receives power delivered at high voltage. Transformers at these points lower the voltage for power distribution.

Bus - An electrical conductor which serves as a common connection for two or more electrical circuits. A bus may be in the form of rigid bars, either circular or rectangular in cross section, or in form of stranded-conductor overhead cables held under tension.

Busbar - An electrical conductor in the form of rigid bars, located in switchyard or powerplants, serving as a common connection for two or more electrical circuits.

Capacitor - A dielectric device which momentarily absorbs and stores electrical energy.

Capacity - The maximum power output or load for which a machine, apparatus, station, or system is rated.

Capacity or Capability - The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer.

Capacity Factor - The ratio of the average load on a machine or equipment for the period of the time considered, to the capacity rating of the machine or equipment.

Capacity Interchange - In power pooling, transactions resulting from the assignment by participating utilities of reserve or excess generating capacity for common use.

Central Station Service - Refers to electric service supplied from an electric system rather than by self-generation.

Circuit Breaker - A switch that automatically opens an electric circuit carrying power when an abnormal condition occurs.

Coal Slurry Pipeline - A pipeline which transports coal in pulverized form suspended in water.

Coincident - Occurring at the same time.

Coincident Demand - Any demand that occurs simultaneously with any other demand; also the sum of any set of coincident demands.

Commercial Paper - Short-term promissory note issued and sold by utilities and other companies usually through dealers in such paper.

Condenser - In a steam electric plant, a device which condenses steam into water after the steam has gone through the turbine before it is injected into the boiler for reuse.

Connected Load - The sum of the capacities of the elctric power consuming devices connected to a supplying system.

Contingency - Deviation from normal operating procedures, such as outages of generation or transmission lines.

Coordinated Operation - The cooperative action by two or more electric utilities to operate their electrical systems in a manner intended to achieve mutually the optimum economies and reliability of overall system power supply.

Coordinated Planning and Development - The cooperative action by two or more electric utilities to plan their generation and transmission facilities additions and thenceforth implement those planned additions in a manner intended to achieve mutually the optimum economies and reliability of overall system power supply.

Coordination - Cooperative action by two or more systems to achieve the economies of overall power supply and network integration.

Critical (as related to nuclear material) - The condition whereby an atomic chain reaction is capable of being sustained in a nuclear reactor.

Critical Streamflow - The amount of water available for hydroelectric power generation during the most adverse streamflow period.

Demand - The rate at which electric energy is delivered to or by a system or to a piece of equipment expressed in kilowatts, kilovolt-amperes, or other suitable unit at a given instant or averaged over any designated period of time. See Load.

Demand or Load - The rate at which electric energy is delivered or required, usually expressed in kilowatts (kW) or megawatts (MW). Unless otherwise indicated, it is generally understood to mean the average rate over a 1-hour period.

Desalination Plant - A water supply plant which removes salt from sea water or brackish water to produce potable water.

Direct Current (dc) - Electricity that flows continuously in one direction as contrasted with alternating current.

Dispatching - The operating control of generating units, transmission lines, and other facilities including assigning of generator outputs as needed, controlling maintenance and switching operations, and scheduling energy transactions with other utilities.

Distribution - The act or process of distributing electric energy.

Diversity - The differences among individual electric loads resulting from the fact that the maximum demands of customers do not all occur at the same time.

Diversity Exchange - Capacity and/or energy exchange which is possible due to the difference between coincident and noncoincident demands of two or more systems.

Diversity Load - The difference between the peak of coincident and non-coincident demands of two or more individual loads.

Economy Energy - Energy produced and supplied from a more economical source, substituted for energy that could have been produced by a less economical source.

Economy Power - Capacity and/or energy available from source(s) in one system used as a substitute for a less economical source(s) on another system.

Emergency Power - Capacity and energy supplied to a system experiencing breakdown of equipment, unusual load demands, or abnormal conditions resulting in a need for power in excess of that available from its normal power sources.

Energy - That which does or is capable of doirg work, and is equal to average power multiplied by the interval of time.

Energy (Electrical) - The integrated load or demand over a period of time, generally expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).

Energy Requirements - The amount of electric energy needed by a utility to serve its customers and to cover system losses.

Extra High Voltage (EHV) - Generally used to refer to voltages of 230 kilovolts to 800 kilovolts.

Firm Capacity - The dependable capacity of system facilities available for serving system load after allowance for required reserve capacity, including the effect of emergency interchange agreements and firm power agreements with other systems.

Firm Energy - Electric energy which is intended to have assured availability to the customer to meet all or any agreed upon portion of his load requirements.

Firm Power - Capacity and energy intended to have assured availability to the customer to meet all or any agreed-upon portion of its load requirements.

Fission - The release of energy through the process whereby the nucleus of an element captures a neutron and splits into two nuclei of lighter elements.

Forced Outage - The shutting down of a generating unit, transmission line, or other facility, for emergency reasons.

Fossil Fuels - (As used in this report) Refers to coal, oil, and natural gas.

Francis-Type Unit - A hydraulic turbine using vanes to drive generating equipment. Water enters the unit at a right angle.

Frequency - In alternating current (ac) systems, the rate of change alternating from positive to negative polarity.

Fusion - The combining of atomic nuclei of very light elements by collision at high speed to form new and heavier elements, resulting in the release of energy.

G&T Cooperatives - Electric utility cooperatives which generate and transmit electric power usually at wholesale to distribution cooperatives and other member systems.

Gaseous Diffusion - A method of isotope separation used to enrich uranium with the uranium-235 isotope. Based on the fact that atoms or molecules of different masses will diffuse through a porous barrier at different rates.

Generation, Electric - The process of transforming other forms of energy into electric energy.

Generation Mix - The number and types of power generation projects being operated by a single utility or a group of utilities. Examples of generation project types that a utility might operate would include: hydroelectric, fossil-fueled steam, nuclear-fueled steam, combustion turbines, and diesel engines.

Generator - A machine which converts mechanical energy into electric energy.

Gigawatt (GW) - One million kilowatts.

Gross National Product (GNP) - The Nation's total national output of goods and services at current market prices.

Head, Gross - The difference of elevation between the headwater surface above and the tailwater surface below a hydroelectric powerplant, under specified conditions.

Heat Rate - A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is the total Btu content of fuel burned or of heat released from a nuclear reactor for electric generation by per net kilowatt-hour generation.

Heavy Water - Water used in the moderation of nuclear reaction by certain types of atomic powerplants. In this water (D_2O), the hydrogen of the water molecule consists entirely of deuterium - the heavy hydrogen isotope of mass 2.

Hertz - Cycles per second.

Holding Company - A nonoperating company which controls other companies through stock ownership.

Hydroelectric Plant - An electric powerplant in which the turbine-generators are driven by falling water.

Inadvertent Energy - The difference between net actual energy flow and net scheduled energy flow to or from a system.

Inertial Characteristics - Parameters of the rotating electromechanical machinery in an electric system which determine the amount of inertia mechanically stored in the machines that is available to respond to the electric system in the event of a disturbance.

Instability - Electromechanical response of the elements of an electric power system to a disturbance, which results in loss of synchronism.

Integral Train - Similar to unit train except that the cars are more or less permanently coupled.

Interconnection - A transmission line joining two or more power systems through which power produced by one can be used by the other. Also, intertie.

Intermediate Load Power or Intermediate Generation - Those generation resources used to supply power and energy for that portion of the load cycle between that supplied by the Baseload and the Peaking Generation.

Interrupting Rating - The highest current at a specified voltage that an electrical circuit opening device, such as a circuit breaker or a fuse, is required to interrupt. If a circuit opening device attempts to interrupt currents of greater magnitude than its interrupting rating, hazards to property and personnel are incurred.

Intertie - See Interconnection.

Isolated - Operating alone as an electric system, without interconnections to other systems.

Joint Planning and Development - The cooperative action by two or more electric utilities to plan specified facility additions and thenceforth to implement those planned additions in a manner intended to achieve mutually certain economic and operational benefits.

Kaplan Unit - A hydraulic turbine using propellor-shaped blades, which are adjustable under load, to drive generating equipment.

Kilovolt (kV) - One thousand volts.

Kilowatt (kW) - One thousand watts.

Kilowatt-Hour (kWh) - The amount of electrical energy involved with a 1-kilowatt demand over a period of 1 hour. It is equivalent to 3,413 Btu of heat energy.

Lignite - A low grade coal of a variety intermediate between peat and bituminous coal.

Line Compensation - The balancing out of line impedance.

Line Impedance - The apparent opposition to the flow of alternating current that is analogous to the actual electrical resistance to a direct current.

Load - The amount of power needed to be delivered at a given point on an electric system.

Load Center - The point in which the loads of a given area are assumed to be concentrated for purposes of analysis.

Load Curve - A curve showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.

Load Cycle - The plotted values of the variation in hourly demands over a period of time.

Load Diversity - The difference between the sum of two or more individual peakloads and the coincident or combined maximum load, usually measured in power units.

Load Factor - The ratio of the average load supplied during a designated period to the peak or maximum load occurring in the same period.

Load Flow Studies - Simulation of the steady-state flow of electricity on electric system transmission lines to analyze line power loadings under various conditions.

Load Frequency Control - Supplementary regulation by automatic means responsive to frequency, interconnection power flow, area generation, and other parameters to regulate the area generation to obtain the desired net interchange.

Load Growth - The growth in energy and power demands by a utility's customers.

Maintenance Power - Capacity and/or energy supplied to a system to supplement its power sources during periods of planned outages of generating equipment.

Margin - The difference between the net system generating capability and system maximum load requirements including net schedule transfers with other systems.

Megawatt (MW) - One thousand kilowatts.

Megawatt-Hours (MWh) - One thousand kilowatt-hours.

Metallic Return - Use of an electric conductor at ground potential (0 kV) in monopolar dc transmission for the return path; this avoids potential problems with using the earth to carry the return current.

Mine-Mouth Steam-Electric - A steam-electric plant built close to coal mines and usually associated with delivery of output via transmission lines over long distances as contrasted with plants located nearer load centers and at some distance from sources of fuel supply.

Minimum Load - The minimum demand during a given time period.

Monopolar - Having only one level of electric potential as in +450 kV direct current transmission; the return path is at ground potential (0 kV) and can be provided by injecting return current into the earth, or by use of a second conductor, known as a metallic return.

Multi-Purpose River Basin Program - Programs for the development of rivers with dams and related structures which serve more than one purpose, such as hydroelectric power, irrigation, water supply, water quality control, and fish and wildlife enhancement.

Multi-Purpose Transmission Line - Employment of a transmission line for more than one function, such as regular transmission, wheeling, reserve capacity, and peak capacity usage.

Noncoincident - Occurring at different times.

Nondisplacement Power - Capacity and/or energy available from surplus capacity in one system supplied to another system which lacks the capacity to supply the energy from its own resources. Supplied for short intervals on an if-and-when-available basis. (Unlike short-term power, the supplying party has no reserve responsibility.)

Nonfirm Power - Capacity and/or energy which does not have assured availability to the customer. Nonfirm power is only as dependable as the source(s) from which it is derived, i.e., it is power without reserve backup.

Nonspinning Reserves - Cold and hot reserves. Cold reserve: Thermal generating capacity available for service but not maintained at operating temperature. Hot reserve: Thermal generating capacity maintained at a temperature and condition which will permit it to be placed into service promptly.

Nuclear Energy - Energy produced largely in the form of heat during nuclear reactions, which, with conventional generating equipment can be transformed into electric energy.

Nuclear (Atomic) Fuel - Material containing fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.

Nuclear Power - Power released from the heat of nuclear reactions, which is converted to electric power by a turbine-generator unit.

Nuclear reactor - An apparatus in which nuclear fission is achieved in a self-sustained chain reaction.

Offpeak Power - Capactiy and/or energy supplied during periods of relatively low system demands as specified by the supplier.

Onpeak Power - Capacity and/or energy supplied during periods of relatively high system demands as specified by the supplier.

Operating Availability - The percent the unit was available for service, whether operated or not. It is equal to available hours divided by the total hours in the period.

Operating Reserves or System Required Reserve - The system reserve capacity needed as standby to ensure an adequate standard of service.

Outage - The period in which a generating unit, transmission line, or other facility, is out of service.

(In) Parallel - Several units whose ac frequencies are exactly equal, operating in synchronism as part of the same electric system.

Particulate Matter - Solid particles, such as ash, which are released from combustion process in exhaust gases at fossil-fuel plants.

Peaking Capacity - That part of a system's equipment which is operated only during the hours of highest power demand.

Peaking Load - The greatest amount of all of the power loads on a system, or part thereof, which has occurred at one specified period of time.

Peaking Plant - Generating plant supplying energy for electric system requirements as the demand increases towards the peak level; this type of generation normally will be run during the high demand periods of the day and shut down at other times.

Peaking Power or Peaking Generation - Those generation resources used to supply power and energy for the upper part of the load cycle, generally the upper 15 to 20 percent of the load demand.

Peaking Units - Usually old, low-efficiency steam units, gas turbines, diesels, or pumped storage hydro used primarily during the peakload periods.

Peakload - The maximum demand during a given time period.

Plant Factor - The ratio of the average load on the plant for the period of time considered to the aggregate rating of all the generating equipment installed in the plant.

Plutonimum (pu) - A heavy, fissionable, radioactive, metallic element with atomic number 94. Plutonium occurs in nature in trace amounts only. However, it can be produced as a byproduct of the fission reaction in a uranium fueled nuclear reactor and can be recovered for future use.

Pondage - The amount of water stored behind a hydroelectric dam of relatively small storage capacity used for daily or weekly regulation of the flow of a river.

Power (electric) - The time rate of generating, transferring or using electric energy, usually expressed in kilowatts (kW) or megawatts (MW). Sometimes used broadly to refer to both capacity and energy.

Power Factor - The percentage ratio of the amount of power, measured in kilowatts, used by a consuming electric facility to the apparent power measured in kilovolt-amperes.

Power Pool - Two or more electric systems which are interconnected and coordinated to a greater or lesser degree to supply, in the most economical manner, electric power for their combined loads.

Preference Customers - Publicly owned systems and nonprofit cooperatives which, by law, have preference over investor-owned systems for the purchase of power from Federal projects.

Prime Mover - The engine, turbine, water wheel, or similar machine which drives an electric generator.

Pumped Storage - An arrangement whereby electric power is generated during peakload periods by using water previously pumped into a storage reservoir during offpeak periods.

Pumped Storage Plant - generating plant consisting of hydroelectric generators with reversible pump turbines where water is pumped to a higher level for storage using available lower cost energy during offpeak load periods, later to be released to the lower level in peakload hours to generate electricity.

Reaeration - The process whereby the oxygen content of water which has been depleted by heat from thermal powerplants or by a deep position in a reservoir or otherwise is restored to normal level.

Reserve Generating Capacity - Extra capacity maintained to generate power in the event of unusually high demand or a loss or scheduled outage of regular generating capacity.

Reserves or Reserve Capacity - That portion of generating capacity which is in excess of the load.

Revenue Requirements - The amount of money needed to compensate for the financial obligations incurred by a capital investment, including depreciation, interest, return on investment, income taxes, property taxes, etc.

Residual Fuel Oil - Oil remaining after the petroleum refining process is completed

Reverse-Current Relays - A sensing device (relay) used to actuate some other piece of equipment, such as a circuit breaker, when the power flow changes direction along a transmission line.

Reversible Capacity - The characteristic of a single machine permitting it to be used alternately as a motor pump or turbine-generator. It is therefore important for pumped storage developments.

Scheduled Outage - The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance in accordance with an advance schedule.

Seasonal Diversity - Diversity between two or more power systems which occurs when their annual peakloads are in different seasons of the year.

Secondary Hydroelectric Energy - Hydroelectric energy which is not available on a continuous basis under the most adverse hydraulic conditions contemplated.

Series Capacitors - A bank of capacitors connected in series with an electric power transmission line which are used to control the magnetic component of line impedance.

Series Compensation - Use of capacitors in series with transmission lines to compensate for some portion of the reactive impedance of the line (reactive impedance of capacitors is negative) to effectively shorten the transmission line for better performance during disturbances.

Service Outage - The shutdown of a generating unit, transmission line, or other facility for inspection, maintenance, or repair.

Shunt Capacitors - Capacitors connecting from a powerline to a grounded connection, usually designed to reduce that part of the electric current causing a poor power factor.

Spinning Reserve - Generating capacity connected to the bus and ready to take load. It also includes capacity available in generating units that are operating at less than their capability.

Stability - Electromechanical response of the elements of an electric system to a disturbance, which results in establishing of new operating levels as required while maintaining synchronism.

Standby Equipment - Generating equipment that is not normally used but is available, through a permanent connection, to replace or supplement the usual source of supply.

Steam-Electric Plant - A plant in which the prime movers (turbines) connected to the generators are drive by steam.

Surge Impedance Loading - Level of power delivered by a transmission line at which the reactive power supplied by the transmission line due to line charging current equals the reactive power losses due to the line reactive impedance.

Surplus Power - Generating capacity which is not needed on the system at the time it is available.

Switching Surge - The sudden traveling waves of electric power on transmission lines and resultant voltage changes induced by switching lines in or out of service.

Synchronous - Describing two or more electric power systems electrically locked in at the same frequency or rate of alternating between positive and negative polarity in ac systems.

System Breakup - The response of an electric power system in instability which results in opening transmission lines by protective relay action due to loss of synchronism so that the system does not remain intact.

System, Electric - The physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control, management, or operating supervision.

Tap - A connection from one transmission line to another or to a substation.

Thermal Plant - A generating plant which uses heat to produce electricity. Such plants may burn coal, gas, oil, or use nuclear energy to produce thermal energy.

Thermal Pollution - Rise in temperature of water such as that resulting from heat released by a thermal plant to the cooling water when the effects on other uses of the water are detrimental.

Tie-Line - Transmission line connecting two systems.

Time Zone Diversity - Diversity between systems in different time zones resulting from time difference as it affects the demands for power.

Transformer - An electromagnetic device for changing the voltage of alternating current electricity.

Transmission - The act or process of transporting electric energy in bulk (usually at 69 kVA or higher).

Transient Stability Studies - Simulation of the electromechanical response of an electric power system immediately after the start of a disturbance; the transient period during which the elements of the system seek new operating levels as a result of the disturbance is analyzed.

Turbine - The part of a generating unit which is spun by the force of water or steam to drive an electric generator. The turbine usually consists of a series of curved vanes or blades on a central spindle.

Turbine-Generator - A rotary-type unit consisting of a turbine and an electric generator. (See Turbine and Generator.)

Turn-Key Proposal - A job in which responsibility for all features of a development is undertaken by a single contractor.

Ultra High Voltage (UHV) - Generally used to refer to voltages above 800 kilovolts.

Unit Train - An entire train used for one purpose such as to transport coal directly from coal fields to a generating plant.

Var Requirements - Vars (volt-amperes-reactive) are units of reactive power, as compared to watts as units of active power; direct current converters require vars from the alternating current system in order to operate.

Vertically Integrated System - Refers to power systems which combine generation, transmission, and distribution functions.

Voltage of a Circuit - The electric potential difference between conductors or conductors to ground, usually expressed in volts or kilovolts.

Watt - The rate of energy transfer equivalent to one ampere under a pressure of one volt at unity power factor.

Wheeling - Transportation of electricity by a utility over its lines for another utility; also includes the receipt from and delivery to another system of like amounts but not necessarily the same energy.

APPENDIXES

Appendix I

Addendum to Congressional Research Service Study

The Library of Congress
Congressional Research Service
Washington, D.C. 20540

A NATIONAL POWER GRID SYSTEM AND THE ENVIRONMENT*

Prepared By

Gary J. Pagliano
Analyst in Environmental Policy
Environment and Natural Resources Policy Division

November 11, 1975

---

*Prepared in coordination with Library of Congress Contract 75-22, A Study of a National Power Grid System.

A wide range of environmental issues is associated with generating and transmission of electricity. In this chapter, some of the issues are treated in the broad context of existing electrical generating and transmission facilities as well as primary fuel supplying facilities because these electric power facilities would comprise most of the national power grid system. Specifically, this chapter will focus on the impact that present facilities' siting and operation have on land, air, water, and on human physiology along with the environmental consequences of additional actions necessary to complete a national power grid. These actions as identified by the study include the following:

1. Interconnecting the separately operating systems of the Far West and the Midwest with at least two high voltage transmission lines each 1,500 miles in length.
2. Interconnecting the Electric Reliability Council of Texas operating systems with the operating systems of the Southwest Power Pool.
3. Developing one or more large generating centers at strategic locations in the coal-rich areas in the West to serve loads in both the Midwest and Far West.

In addition, this chapter will describe the present Federal environmental regulatory structure within which the national power grid would have to function.

Power Plant Facilities

In the power plant, primary fuel feedstock is converted into electric output which is transmitted to hundreds of different consumers. Fossil fuel power plants are presently the mainstay of the electric power industry. These plants currently account for about 76 percent of total generating capac however, with increased reliance on nuclear power, the fossil fuel power plants are expected to account for only about 44 percent of capacity by 1990.[1] Whether the power plant is a fossil fuel plant or a nuclear power plant, there is an environmental impact involved.

Land Use

The power plant's cooling system greatly influences the requirements for land. The once-through cooling systems and the cooling tower systems usually require only a few acres of land. However, cooling ponds need significantly more land for cooling purposes; some estimate a 1000 megawatt plant would require about 2000 acres for a pond depending on depth of the pond and the average heat exchange factor.[2] To optimize the cooling pond size though, the analyses would in addition have to include site specific factors such as site meterorology, and hydrology.

Other land requirements are associated with waste management. The coal-fired power plant's solid waste system, for example, is usually the lime and limestone scrubbing systems which produce large quantities of semi-solid sludge requiring land for storage. With the threat of space availability problems, some power plants convert wet sludge to a material useful for land fill. Numerous land fill sites are available in the United States, especially in areas where there has been strip mining.

An alternative scrubbing system is the regenerable systems, such as magnesium oxide and catalytic oxidation, which do not produce sludge. Instead, these systems regenerate the scrubbing agent and produce such valuable materials as elemental sulfur and sulfuric acid.

The increasing environmental consequences of power plant cooling and waste systems on the land has generated concern in the Federal and State governments. At least eighteen states have enacted their own power plant siting legislation.[3] The states have created a variety of committees, boards and other bodies empowered to make siting decisions usually in coordination with long-range state land use planning and power demand forecasts.

On the Federal level, the Coastal Zone Management Act of 1972[4] provides financial and technical assistance to states wishing to developing coastal zone management programs. To qualify for Federal assistance, the state must provide assurance to the Secretary of Commerce that the energy facility to be sited is in the national interest. With the coastal zone an important site for power plants, this law provides a basis for more direct federal intervention in state power plant siting decisions.

The Energy Reorganization Act of 1974[5] directs the newly-established Nuclear Regulatory Commission (NRC) to conduct a national survey of possible nuclear energy center sites. The survey would include a regional evaluation of natural resources available for use in connection with nuclear energy sites; an assessment of the economic impact of each site; estimates of further electric power requirements that can be served by each site; an evaluation of the environmental impact likely to result from construction and operation of nuclear energy centers; and consideration of the use of certain types of federally owned property and other property designated for public use.

Currently the NRC's formal siting regulations are limited to the specification of broad site criteria relating only to radiological health and safety considerations. The criteria have been supplemented in effect by specific Commission guidelines for detailed descriptions of the environmental features of a proposed site and the environmental impact resulting from construction and operation of a nuclear power plant on the site. In addition, the Commission requires an analysis of available and alternative sites and types of power plants. An applicant must demonstrate that none of these is clearly preferable to the proposed site.

Air Quality

The electric utility industry consumes about one-fourth of all fuel burned in the United States, but it only contributes about one-eighth of the total mass of pollutants emitted in the air.6/ Particulates, sulfur oxides and nitrogen oxides are the most extensive air pollutants from fossil fueled power plants. These plants until recently accounted for almost one-half of the suflur oxide national total because of the extensive use of high sulfur fuels.7/ While changes in fuel use in recent years have helped change this pattern, probably the most significant factor has been Federal and State air pollution legislation.

Recent Federal and State legislation, culminating in the Clean Air Act of 1970,8/ has greatly strengthened regulatory powers over air pollution and, among other provisions, has mandated the establishment of the national air ambient quality standards. The Clean Air Act of 1970 established a comprehensive scheme of air quality regulations which rely primarily on States accommodating national standards set by the Environmental Protection Agency (EPA). Although EPA reviews and monitors each state plan, it avoids any federal preemption of ultimate state authority by expressly providing that states may adopt and enforce pollution standards and emission limitations more stringent than any comparable Federal standards.

The national ambient air quality standards affect the fossil-fired generation by limiting the quantities of particulates, sulfur dioxide and nitrogen oxides that may be released into the atmosphere by the facility.[9] Using these standards, the EPA or the state will evaluate a proposed fossil-fired power plant projected emissions along with the emission effects of other pollution sources in the area affected by the plant.

Water Quality and Availability

The electric power industry relies heavily on the Nation's water resources. It uses but does not consume approximately four-fifths of the total water used by all industry for cooling purposes.[10] The power industry's use of water as a coolant is expected to increase substantially along with the projected expansion of power generating capacity. The National Water Commission has estimated that 190 to 200 billion gallons per day are needed for power plants in the United States by 1980.[11]

The principal ways in which electric power operations can affect water quality are through the discharge, from thermal power installations, of heat, chemicals and, in the case of nuclear facilities, trace amounts of radioactivity. Of these possible sources of effect, thermal pollution is the most significant because of the effect on the oxygen content of the water and on other conditions important to the aquatic eco-system.

In modern fossil-fired power plants up to 40 percent of the heat released in the boiler is converted into electrical energy. The unused heat energy is discharged, about 90 percent of it going into the water use for condenser cooling and the balance being carried into the atmosphere by the stack gases.[12/] Nuclear plants usually operate at lower conversion efficiencies, about 31 percent, and thus discharge more waste heat per kilowatt-hour of electrical output. Since there is no combustion process requiring a stack, essentially all the waste heat from a nuclear plant goes into the turbine condenser cooling water.

Condenser cooling is usually handled by a "once-through" cooling system which entails drawing water from a source such as a river, pumping the water through a condenser and discharging the water back to the source. Typically, the discharged water is from 10 degree to 30 degree F warmer than the inlet stream.[13/]

Even though the discharged warmed water temperature is quickly reduced, there is valid concern that even the slight rise in water temperature may upset the natural balance of aquatic life. Associate Professor L.D. Jensen of The Johns Hopkins University has confirmed that thermal discharge affects water quality, however, the exact effect is unknown at this time.[14/]

The Federal Government has responded to the potential thermal pollution danger by establishing regulations governing warm-water discharge.

The landmark step was the enactment of the Water Quality Act of 1965, however, the latest Federal action, the Federal Water Pollution Control Act of 1972,[15/] established even stricter water standards for new power plants. These standards require "the greatest degree of effluent reduction which the best available demonstrated control technology, processes, operating methods, or other alternatives, can achieve including, where practicable, a standard permitting no discharge of pollutants."[16/]

As a result EPA has established standards of performance for electric generating plants including both fossil-fired and nuclear plants. The standards restrict to specific limits (concentration levels) the discharge of certain chemical, metallic and other types of pollutants in such generating plant effluents as ash transport water, metal cleaning wastes, boiler "blowdown" (discharge of water to avoid excess concentration of solids) and cooling tower "blowdown."[17/]

With regard to thermal discharges, the standards of performance for new electric plants prohibit the use of "once-through" cooling systems and require that "closed-cycle" systems be used.[18/] A "closed-cycle" system is one that retains most of the coolant within the system, types of which include cooling towers and man-made cooling ponds. New electric generating plants equipped with closed-cycle cooling systems meeting all applicable standards of performance would not be subject to more stringent standards for a period of ten years after completion of construction.

Radiologic Considerations

Detailed consideration of radiologic environmental aspects of the nuclear power plant is beyond the scope of this chapter; however, some general observations can be made. Nuclear plant-environmental issues center around: first, the release of large quantities of radioactive materials that could result from a potential accident disrupting the primary cooling system in which adequate heat removal could not be achieved; second, the radiotoxicity of plutomium and the difficulty of adequate control of plutonium as it may become increasingly used as fuel material in the plutonium recycle in light water reactors and liquid metal fast breeders; and third, the ultimate disposal or long term management of highly radioactive waste materials evolving from reprocessing of spent nuclear fuels.

Studies are currently in progress addressing potential environmental problems with nuclear power plants. One of the more important studies is on the assessment of accident risks in United States commercial nuclear power plants being directed by Professor Norman Rassmussen of the Massachusetts Institute of Technology. One of the preliminary conclusions reached by the study was that the consequences of potential reactor accidents are no larger, and in many cases, are much smaller than those of non-nuclear accidents.[20/]

Energy Parks

One course of action identified in this study is the possibility of one or more large generating centers at strategic locations in the coal-rich areas in the West. In order to evaluate the environmental impact of such generating centers, an assumption must be made about the siting pattern of the large electric power plants. The usual dispersed siting pattern for example could have about 24 coal fired power plants (each about 1,100 MWe) within an area of 2,000 square miles. If, however, the same 24 coal-fired power plants were within 0.84 square mile of each other, the siting pattern could be called a basic energy park. The basic coal-fired energy park, still in the conceptual stage, would eliminate most of the primary fuel transportation costs because the park complex is located at the mining site.

Once the complex was finished, the scale of coal consumption and electric power output would exceed any norm of today. When all 24 units are on line, the coal consumed would be 55 to 73 million tons a year and the electric power output would approximate 26,200 MWe. For comparison, the 1974 consumption of the entire electric power industry was approximately 390 million tons.

With such a large scale consumption of coal, the potential environmental impact is large. Studies are now under way to determine the potential environmental impact of such energy parks. One recently completed study using two computer simulation models recommended by the EPA, tried to predict the effect that a basic energy park would have on air quality. The study found that all ambient air quality standards for particulates and nitrogen oxides would be satisfied for the basic energy park.21/ However, the energy park's maximum short term, 3 and 24 hour standards, concentrations of SO_2 would greatly exceed standards.22/

Transmission

The need to transport electrical energy efficiently and economically from one location to another in ever increasing amounts had led to continual development of higher and higher transmission voltages. This trend to higher voltages has precipitated concern over possible physiological effects of high voltage lines. In addition, the expansion of such systems and other transmission systems has initiated maximum use rights-of-way in order to minimize the environmental intrusion.

Land Use

Electric utilities operate over 300,000 miles of overhead transmission lines involving 4 million acres of right-of-way.[23/] As electricity demand rises, the utilities may require 4.5 million acres of additional land by the year 2,000.[24/] Although the lines occupy narrow corridors of land, the total projected land use is equal to an area larger than Delaware and Maryland combined.[25/]

The average United States' land requirement for transmission routes on dispersed sites averaging 25 miles from the load is 0.8 acres per 1,000 KW of on-line generation.[26/] As units are located further from the load the land requirements increase at the rate of 1.2 acres per megawatt per 100 miles. For energy parks the figures are higher depending on the location of the parks from the sites, as shown below.

LAND REQUIREMENTS FOR TRANSMISSION, ACRES PER MEGAWATT OF GENERATING

Acre/MW	Capacity
0.8	Dispersed sites
1.4	Parks at near sites
2.6	Parks at intermediate sites
3.8	Parks at far sites

Transmission line licensing authority exists under a maze of jurisdictions. The Federal Power Act authorizes the Federal Power Commission (FPC) to license the construction of primary transmission lines associated with a Federal hydroelectric project under the FPC's jurisdiction.[27/] If the hydroelectric project is under the jurisdiction of another entity, such as the Tennessee Valley Authority (TVA), then that entity (TVA) would have jurisdiction over the construction of the project's transmission lines. Transmission lines associated with other types of electric power projects on public lands will most likely have to obtain a license from the Bureau of Land Management (BLM), Department of the Interior. However, the BLM will sometimes consult with other possible jurisdictional Federal agencies before issuing the license. For example, if national forests were affected by the transmission line application, then the National Forest Service would be consulted before final action on the license.

The licensing of intrastate transmission lines is usually under the jurisdiction of the State. The State may regulate the licensing of intrastate transmission lines as long as the State regulation does not conflict with Federal jurisdictions. If a conflict arises, Federal jurisdiction will usually predominate.[28]

Physiological Effects

Physiological concern over power transmission lines centers around the effects of ozone produced as a result of partial breakdown of insulating media in the power delivery system and of electromagnetic effects produced by the very high voltage transmission lines.

Ozone is very irritating to all mucous membranes, and significant exposures to concentrations above 0.05 parts per million (p.p.m.) may cause pulmonary edema. This was verified by a study in which Flury and Zernik concluded that men exposed to ozone suffer eye, nasal, and throat irritation, chest cramps, vertigo, increasing fatigue, and lowering of blood pressure.[29]

The controversy centers around how much ozone is produced by power transmission lines. One study failed to find any significant increases in the natural ozone level caused by 765 kilovolt (KV) power lines.[30] However, many similar studies are now in progress and no real consensus on ozone production by power lines has been reached at this point.

In addition, power lines produce strong electric fields (caused by electromagnetic forces) and growing evidence indicates that prolonged exposure to these electric fields could cause physiological harm. In the Soviet Union, a long-term study was conducted to examine the possible physiological effects on 250 men working at 500 and 750 kilovolt substations.[31] The study showed that prolonged work at 500 kilovolt substations without protective measures resulted in complications in the central nervous system, heart and blood vessel system, and changing of the blood structure.

In the United States, The Electric Power Research Institute is sponsering study on the biological effects of high voltage transmission lines. In addition, the University of California at Los Angeles is conducting experiments in which monkeys are exposed to electric fields and finding significant alteration of the interresponse time of the exposed animals.32/ Experts believe this change in time perception a very sensitive measure of conditions which, if long term exposure occurred, could result in important behavioral and neurological changes.

Primary Energy Supply Systems

A primary energy supply system consists of all the components necessary to bring a basic energy resource from its natural state to a power generating plant. Most primary energy systems involve extraction, processing, and transportation between the various operations the last of which is the power generating plant. For example, producing electricity from coal requires extraction of the coal from underground or surface mines, then processing for removal of impurities, and transportation by railroad, truck, barge, or slurry pipeline to a power plant. This section will consider coal and nuclear fuel as well as petroleum and natural gas even though the latter two fuels will be phased out from new electric power use by 1985 and 1977 respectively.

Land Use

Coal systems are based on either surface or underground mining. By 1969, surface mining has already affected over 3.5 million acres of land of which only one-third had been restored. Deep coal mines have undermined over 7 million acres, of which over 2 million has already subsided.[33/] Some experts estimate between now and the year 2000, about 4 million additional acres may be undermined from coal extraction.

Most coal is transported by rail and considerable amounts of land are devoted to railroad rights-of-way.

The fuel cycle for light water nuclear power system (LWR) is technologically more complex than the coal plant supply system, but requires relatively little land to supply the needs of a 1,000-megawatt power plant. Uranium ore is extracted from both surface and underground mines; but, because of the high energy content nuclear fuels, neither the mining process nor subsequent nuclear fuel processes involve very much land.

Land requirements for oil and natural gas systems are similar to each other and are primarily related to drilling and transmission. A one thousand megawatt oil-fired power plant requires 1,572 acres[34/] for drilling rigs and 1,656 acres[35/] for a pipeline. A 1,000-megawatt gas-fired power plant requires 321 acres[36/] for drilling rigs and 3,186 acres[37/] for transporting by pipeline. The combined average land requirement for oil and gas extraction and transportation is only 25 percent the land requirement for the same 1,000-megawatt coal-fired power plant support system and approximately four times the land requirement for a 1,000-megawatt light water reactor nuclear power plant (LWR) support system.[38/]

Air and Water Quality

Surface mining often leads to acid mine drainage and silt runoff, both degrading water quality. Underground coal mining also results in acid drainage.

Once the coal is mined, approximately 30 percent of the uncleaned coal is transported directly from the mine to the user. The remaining coal is processed to reduce the inorganic sulfur and ash content. Process solid wastes are piled onto waste banks, and processing waste is often dumped with suspended solids into streaming.

Petroleum extraction and processing involve some hazards to air and water quality. There are potential problems of oil spillage and disposal of large quantities of brine brought up with the oil. The crude oil is generally transported to the refinery by pipeline, which in some instances have ruptured and spilled oil. In addition, the refinery and storage facilities contribute to air and water pollution.

In the LWR fuel cycle, radioactive emissions to air, measured in units of curies, are greatest from the reprocessing plant. The reprocessing take place when spent fuel, containing highly radioactive fission products, is transported to the plant. At the plant, the fuel is chemically treated to recover the remaining uranium and some plutonium produced during the fissio process. Also removed are the fission products which cannot be discharged into the environment but must be monitored and stored indefinitely because of their biological hazards and long half-lives. The liquid wastes must be converted into solids within 5 years, and NRC regulations require the shipment to a federal repository take place within 10 years.

National Power Grid Implications

The environmental impact of a national power grid system depends on the interaction of existing electric power system and the possible actions to complete the national power grid. This chapter has described land, air, water and human physiology consequences of the present power system and of potential system additions emphasizing that research is in progress to determine any more potential environmental hazards associated with electric utilities.

One such area of research, the physiology effects of high voltage transmission lines, is currently causing regulatory complications in New York State. The State Public Service Commission (SPSC) is holding hearings on the health and safety aspects of a 765 KV transmission line proposed by Rochester Gas and Electric, and Niagara Mohawk.[39/] Central to the case is the effect on human beings of electric and magnetic fields caused by high voltage transmission lines. The case has caused enough concern to prompt the state Department of Environmental Conservation and other state agencies to ask the SPSC to hold hearings on making rules concerning electric and magnetic fields along with rules affecting all transmission certification cases. This regulatory concern on the state level could be an indication of possible delay in the licensing of high voltage transmission interconnecting the Far West and the Midwest.

There is also regulatory concern about developing additional large generating centers in the western coal areas. In the Four Corners area, surrounding the junction of the States of New Mexico, Arizona, Utah and Colorado, large scale coal fired power plants have been built with more planned. Construction of planned plants has been delayed and the reason is linked to the environmental complications caused by the power plants. Emissions of existing plants have measurably degraded air quality in the region. Even with installation of the best pollution control technology, development of additional plants will probably result in further air quality degradation.

The planned power plants are potentially significant consumers of the scarce remaining uncommitted water supplies of the arid portions of the West and Southwest. The decisions to preempt this water for power plants to the exclusion of alternative uses are under review by the appropriate branches of the Federal and State governments.

In Montana, which has part of Northern Great Plains coal resources estimated at 1,518 billion tons, environmental concerns have blocked rapid and uncontrolled development of coal resources. Montana has enacted a power plant siting certification process which requires a thorough environmental impact study including among other things, land use, water resources, and air quality impacts.[40/] The application for certification has to be filed at least two years before construction of the planned power plant facility can begin. Upon receipt of the application, a number of state government agencies, such as the Department of Natural Resources and Conservation, along with Federal air and water quality agencies, such as the EPA, study the proposal. Agency studies are submitted to the Board of Natural Resources and Conservation who makes the ultimate decision on the certification.

The Montana, Four Corners and New York cases demonstrate that possible regulatory complications associated with high voltage transmission lines and development of western coal areas will probably add to the already long lead times necessary for the planning and construction of such ventures. These extended long lead times could significantly delay the installation of facilities leading to the completion of a national power grid system.

However if the coal-fired power plants were constructed creating significantly new electric power capacity in the western coal area, with high capacity transmission lines carrying power both East and West, then the new system would cause an additional environmental impact. The new system would cause an environmental impact redistribution. The marginal environmental impact attributed to the new national power grid system would shift from the areas receiving the additional power, namely the Far West and Midwest, to the western areas generating the additional power.

FOOTNOTES

1/ Federal Power Commission, The National Power, 1970, Part I, Chapter 5, p. 1.

2/ General Electric Company, Assessment of Energy Parks vs. Dispersed Electric Power Generating Facilities, 1975, Part I, Chapter 7, p. 7.

3/ *Ibid.*, Chapter 6, p. 50.

4/ 16 USC SS 1451-1464 (1970), Public Law 92-583.

5/ 88 Stat. 1233, Public Law 93-438.

6/ Federal Power Commission, The National Power Survey, 1970, Part I, Chapter 11, p. 1.

7/ *Ibid.*, p. 2.

8/ 42 USC SS 1857 *et seq*. (1970), Public Law 91-604.

9/ 40 C.F.R. Part 60, Subpart D. For example, particulates are limited to 10 lb. per million Btu, sulfur dioxide to 1.2 lb. per million Btu, sulfur dioxide to 1.2 lb. per million Btu from solid fuel (except lignite).

10/ Federal Power Commission, The National Power Survey, 1970, Part I, Chapter 1, p. 25.

11/ Water Policies for the Future, National Water Commission Final Report to the President and the Congress of the United States, 1973, p. 11.

12/ Federal Power Commission, The National Power Survey, 1970, Part I, Chapter 1, p. 25.

13/ Federal Power Commission, The National Power Survey, 1970, Part I, Chapter 10, p. 1.

14/ Effects and Methods of Control of Thermal Discharges, Report to the Congress by the Environmental Protection Agency in Accordance with Section 104(t) of the Federal Water Pollution Control Act Amendments of 1972, 1973, Part I, p. 7.

15/ 33 USC SS 1251 *et seq*. (1970), Public Law 92-500.

16/ Section 306, 33 USC SS 1316 (1970).

17/ 40 C.F.R. Part 423.

18/ Ibid.

19/ The United States Atomic Energy Commission, An Assessment of Accident Risks in United States Nuclear Power Plants, 1974.

20/ Ibid.

21/ General Electric Company, Assessment of Energy Parks v. Dispersed Electric Power Generating Facilities, 1975, Part I, Chapter 1, p. 101.

22/ Ibid.

23/ United States Department of the Interior, and the United States Department of Agriculture, Environmental Criteria for Electric Transmission Systems, 1970, Washington, p. iii.

24/ Ibid.

25/ Ibid.

26/ General Electric Company, Assessment of Energy Parks vs. Dispersed Electric Power Generating Facilities, 1975, Chapter 3, p. 20.

27/ 41 Stat. 1063, 16 USC SS 800 (1964).

28/ 16 U.S.C. SS 824f (1970).

29/ Institute de Recherche de L'Hydro-Quebec, Certain Ecological Effects of High-Voltage Power Lines, 1975, p. 30.

30/ Frydman and Levy, Oxidant Measurements in the Vicinity of Energized 765KV Lines, IEEE Trans. Power App. and Systems, Vol. 92, No. 3, May/June 1973, pp. 1141-1148.

31/ V.P. Korobhova, Yu. A Morozov, M.D. Stolarov and Yu. A. Yakub, Influences of the Electric Field in 500 and 750 kilovolt Switchyards on Maintenance Staff and Means for Its Protection, Paper presented at International Conference on Large High Tension Electric Systems (CIGRE), Paris, August-September, 1972.

32/ Dr. Ross Adey, UCLA School of Medicine, to Louise B. Young, January 1974.

33/ United States Department of the Interior, Surface Mining and Our Environment, Washington, D.C., 1967, pp. 39, 42.

34/ One thousand seventy-two shore wells are required to supply a 1,000-MWe plant, based on average well production for the United States. A U.S. Department of the Interior, Bureau of Mines. December 1971. Mineral Industry Surveys: Crude petroleum, Petroleum Products, and Natural-Gas-Liquids: 970. Land area required for drilling rig and attendant equipment and supplies is estimated at 1 acre per well. Intertechnology Corporation, Warrenton, Va.

35/ Land impact for pipeline transport is based on 1969 figures for total U.S. crude oil truck-line mileage (73,830) times the fraction of the total number of wells in the U.S. needed for a 1,000-MWe plant. American Petroleum Institute. 1971. Petroleum Facts and Figures--1971 Edition. Washington, D.C.: A.P.L., p. 215; and notes 1 and 2. A 62.5 foot right-of-way is assumed, averaged from data in Petroleum Extension Service and Pipeline Contractors Association. 1966. A Primer of Pipe Line Construction. Austin: Texas Education Agency.

36/ Based on United States Department of the Interior. Bureau of Mines. 1971. Minerals Yearbook--1969. Washington, D.C.: Government Printing Office, p. 744, a 1,000-MWe powerplant uses 0.28 percent of natural gas production. Each gas well is assumed to require 1 acre.

37/ Total land use is the sum of land impacts due to field and gathering lines right-of-way (1,377 acres), gas transmission mains right-of-way (1,754 acres), and compression stations (55 acres). The field and gathering line figure is based on the share (0.0031) of the total marketed domestically produced gas of the national total of field and gathering mains (64,914 miles). U.S. Bureau of the Census. 1971. Statistical Abstract of the United States: 1971. Washington, D.C.: Government Printing Office, p. 504. Also based on an estimate of a 62.5 foot right-of-way surrounding a gas pipeline. Averaged from data in Petroleum Extension Service and Pipeline Contractors Association, 1966. A Primer of Pipe Line Construction. Austin: Texas Education Agency. Estimates for transmission right-of-way are based upon a procedure similar to that used for field and gathering lines. Statistical Abstract of the United States: 1971, op. cit. Only one-third of the number is used as the land impact of the 1,000-MWe powerplant to compensate for the fact that much of the gas used for powerplants is used near the sites of extraction and processing. Compression station land impact is based upon an estimated frequency of compressor stations of one per 75 miles and an estimated compressor site requirement of 10 acres per site. Federal Power Commission February 1972. "Opinion No. 612: Arkansas Louisiana Gas Company, Docket No. CP70-267." Washington, D.C.: F.P.C., p. 5.

38/ Council on Environmental Quality, Energy and the Environment: Electric Power, Washington, D.C., United States Government Printing Office, 1973.

39/ New York State Public Service Commission, Case 26559.

40/ Mont. Rev. Codes Ann. SS 70-801 to 70-823 (Supp. 1974).

THE LIBRARY OF CONGRESS
Congressional Research Service

WASHINGTON, D.C. 20540

LEGAL ISSUES RELATING TO A NATIONAL POWER GRID

Prepared as a Supplementary Portion of
Library of Congress Contract No. 75-22

BY

Robert D. Poling
Legislative Attorney
American Law Division
November 17, 1975

LEGAL ISSUES RELATING TO A NATIONAL POWER GRID

Introduction

There are a number of significant legal considerations which are relevant to the policy questions raised by a possible national electrical power grid. The purpose of this section of the study is to identify and briefly analyze those major legal issues.

Because a number of alternative legislative methods of effecting a national electrical power grid appear to exist, it is not the purpose of this section to evaluate the legal problems incident to all or even some of those alternatives. Rather, general legal background will be provided for the purpose of outlining the present jurisdiction of the Federal Power Commission. In addition, constitutional considerations relating to extension of Federal jurisdiction over electrical generation, transmission, and sales will be reviewed. Issues involving antitrust law, state utility law and other areas will also be discussed.

It must be stated at the outset that the nature of generation, transmission, and sale of electrical energy in the United States touches on local, state, and Federal laws, all of which encompass wide areas of law.

Present Federal Power Commission Jurisdiction

Since its creation in 1920, the Federal Power Commission has exercised jurisdiction in the public interest over the transmission and wholesale of electrical energy in interstate commerce.

Pursuant to the authority of Sections 201 et. seq. of the Federal Power Act, 49 Stat. 848 (1920), 16 U.S. Code Section 824 et seq., the FPC authorizes the interconnection of electrical facilities,[1/] authorizes the sale, merger and other disposition of electrical facilities,[2/] authorizes the issuance of securities,[3/] and fixes rates and charges for production and transmission of electrical energy.[4/]

These powers are applicable to interstate activities as defined in the FPC's jurisdiction by 16 U.S. Code Section 824:

> § 824. Declaration of policy; application of subchapter; definitions
>
> (a) It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.
>
> (b) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall

> not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transitter.
>
> (c) For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

The jurisdiction of the FPC has been the subject of substantial litigation.[5] Without an exhaustive analysis of that litigation, it might be concluded that the FPC has broad authority in the application of its statutory jurisdiction.[6] However, it might be noted that relatively recent "pooling" of electrical energy for interstate sales has raised issues relating to the tracing of sources of electric energy for the purposes of determining FPC jurisdiction.[7]

The statutory definition of the jurisdiction of the FPC has presented, as the consequence of its legal interpretation, the difficulty of determining exactly what electrical facilities fall within the jurisdiction of the FPC.[8]

Interconnection Authority

The authority which the FPC has over the interconnection of electrical energy facilities is particularly important in any discussion of a possible national electric power grid, for it is this authority to allow interconnection which has already resulted in substantial coordination among generating and transmission facilities.

The primary authority of the FPC to promote electrical power reliability is provided in its authority to create regional districts for the voluntary interconnection and coordination of various electrical facilities:

> 16 U.S. Code Section 824a.
> Interconnection and coordination of facilities; emergencies; transmission to foreign countries--Regional districts; establishment; notice to State commissions
>
> (a) For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnected and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts. Before establishing any such district and fixing or modifying the boundaries thereof the Commission shall give notice to the State Commission of each State situated wholly or in part within such district, and shall afford each such State commission reasonable opportunity to present its views and recommendations, and shall receive and consider such views and recommendations.

The most significant aspect of Section 824a(a) is that the interconnection on the part of the utilities owning the facilities is voluntary. The role of the Commission is that of encouragement, which might take form under other powers of the Commission, such as the rate-making powers. 9/ The actual decision to interconnect must be initiated by the utility or the state commission and may involve several considerations, not the least of which is the possible invocation of the Commission's jurisdiction. 10/

The FPC may, upon the application of a state regulatory commission or any person engaged in transmission or sale of electrical energy, order the interconnection of facilities pursuant to 16 U.S. Code Section 824a:

> (b) Whenever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utilities affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: Provided, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers. The Commission may prescribe the terms and conditions of the arrangement to be made between the persons affected by any such order, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.

Under the language of this provision the FPC has no authority to order the sale or exchange of energy when such action would impair adequate service to the customers of the seller.[11] And it is also well established that interconnection, sale and "wheeling" of power are voluntary and not within the authority of the Commission to order on its own initiative.

> So far as wheeling is concerned, there is no authority granted the Commission under Part II of the Federal Power Act to order it, for the bills originally introduced contained common carrier provisions which were deleted. The Act as passed contained only the interconnection provision set forth in §202(b) [16 U.S. Code Section 824a(b)]. The common carrier provision in the original bill and the power to direct wheeling were left to the "voluntary coordination of electric facilities."[12]

It appears that the only circumstances under which the FPC may order interconnection on its own initiative are war and certain emergency power shortages, as provided by 16 U.S. Code Section 824a(c):

> (c) During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

Under these temporary circumstances the interconnection of facilities not already under the regulation of the Commission does not invoke the jurisdiction of the Commission.[13/]

A central question in determining the Commission's powers under this emergency authority has been resolved only to a limited extent by the definition of emergency as provided in 18 C.F.R. Section 32.20, which was promulgated pursuant to the Commission's general rule-making powers and which provides:

> "Emergency", as used in section 202(d) of the Federal Power Act [16 U.S. Code Section 824a(d)], is defined to mean the failure of facilities for the generation or transmission of electric energy caused by breakdown, weather conditions, acts of God, or other unforeseen occurrences, not reasonably within the power of the utility affected to

> prevent, resulting in the cutting off or curtailment of the electric service, or rendering such utility unable to provide adequate service for its customers.

A somewhat curious difference appears to exist between the scope of emergency powers authorized by the statute and the definition found in the regulation, which appears more restrictive. The scope of either of these provisions is without serious judicial interpretation. Although the basis upon which the Commission could, without hearing and notice, order interconnection has not been clearly litigated, there appears to be some distinction between the voluntary authority of Section 824a(b) and the emergency authority of Section 824a(c).[14/]

It therefore seems that the term "emergency", and its limited definition, provide little authority to the Commission to initiate interconnection of facilities to avoid foreseeable power shortages, or for other purposes, such as the reduction of power reserve requirements. Coupled with the inability of the Commission to order the sale or the "wheeling" of power, it would appear that the Commission exercises extremely limited authority to provide for nationwide planning and coordination of electrical generation capacity and transmission capability.

The extent to which the FPC has attempted to use the emergency interconnection authority is difficult to ascertain,[15/] but the Commission has been criticized for not asserting the full breadth of this authority.[16/] It does appear, however, that the FPC has been reluctant to invoke these emergency powers in recent electrical blackouts.[17/]

Even though the FPC has the obligation to insure adequacy of service under the provision of 16 U.S. Code Section 824g, it does not appear that there is judicial interpretation which reflects attempts at some enforcement of the obligation.

Although it does not appear that there has ever been an attempt to exercise the adequacy of service authority, it would seem that it could provide an additional basis for the use of broader interconnection powers, especially for the purpose of averting power shortages.

Whether or not the FPC has exercised the full breadth of its present statutory authority for the purpose of greater coordination of generating and transmission facilities, it does appear that present authority is limited and does not give sufficiently clear direction and guidance for the implementation of national power grid alternatives. Since the FPC mandate has not been significantly amended since 1920, technological and regulatory considerations relevant to present needs would appear to raise questions which could be resolved by a legislative review of the FPC's authority.

The Commerce Clause

It would appear that the present statutory authority over electrical power delegated by the Congress to the FPC is well within the bounds of constitutional limits. In fact, it does not appear that serious constitutional questions involving this delegation have ever reached the Supreme Court.

Certainly broader delegations of authority, with more expansive definitions of Federal jurisdiction, could be made to the FPC or some other federal entity in such a fashion as to withstand constitutional tests.

Congress is authorized to regulate interstate commerce by Article I, Section 8 of the U.S. Constitution, which provides in part:

> The Congress shall have Power ... To regulate Commerce with foreign Nations, and among the several States ...

In brief, it may be said that the power to regulate commerce is not strictly limited to the regulation of commercial activities which actually cross state lines. The commerce power includes a power to make police regulations to prevent or ameliorate economic, social and other problems not strictly limited to regulating forms and transactions of commercial interstate intercourse. The implementation of the commerce power is not restricted to reaching those matters which actually travel or move in interstate commerce, but extends as well to all those matters in interstate commerce which singly or as a class so affect interstate commerce as to require federal regulation, or which if left unregulated by Federal power would debilitate or undermine the efficacy of Federal regulation.

Thus, purely local matters may be brought under the jurisdiction of the Federal commerce power.[18/] And where Congress finds that the subject matter of activities affect interstate commerce, the courts have held that such findings are entitled to considerable weight.[19/] So long as there appears to be a rational basis for such findings, the courts are not concerned with the manner in which Congress reaches its factual conclusions.[20/]

The principle that Congress may regulate activities pursuant to the Commerce Clause which are intrastate activities that affect interstate commerce is a well established interpretation.[21/]

It would therefore seem that the Congress would have little difficulty in reaching the conclusion, and the courts little difficulty in sustaining the constitutionality, of a much broader exercise of Federal jurisdiction than is presently exercised over the generation, transmission, and sale of electrical energy.

The authorization of a national power grid regulated by a Federal authority (agency or corporation) with powers as expansive as the authority to require interconnection, wheel power, require sales of energy, establish rates and otherwise regulate those engaging in such activities, even where intrastate commerce may be involved, would appear to have firm constitutional rationale.

The extent to which a delegation of new authority on a Federal level would raise conflicts with the jurisdiction presently exercised by the states would, of course, depend upon the nature of the powers vested with the Federal authority. The mere existence of a conflict with state laws would not defeat such legislation, since Federal powers could be exercised which would have the effect of preempting state laws. [22/] Although some adjustment of state laws might be required, the Supremacy Clause of the U.S. Constitution would obviate any conflict with state laws. [23/]

Interstate Compacts

One legal alternative which may be available for use in implementing some types of national grid proposals is the interstate compact. As an alternative in lieu of the outright establishment of increased Federal authority, the interstate compact may offer advantages which capitalize upon the present regional nature of interconnection.

The Federal government could grant authority by means of interstate compacts to allow states to provide for regional mechanisms suitable for the purposes of establishing larger planning and regulatory mechanisms for electrical power.

Article I, Section 10 of the U.S. Constitution provides:

> No State shall, without the Consent of Congress ... enter into any Agreement or Compact with another State...

Since the turn of the twentieth century, the interstate compact has been used to an increasing extent as an instrument for state cooperation in carrying out affirmative programs solving common problems.[24/]

Although Congressional consent usually precedes the compact or agreement, there is some flexibility.[25/]

There are, however, important considerations relating to the practicality of the use of the interstate compact to implement a national power grid proposal. A regional regulatory authority would be subject to regulation by the FPC. Greater Federal regulatory authority might be required to adequately oversee and regulate regional authorities. Even if several authorities were to be established, comprehensive Federal authority would not thereby be created.

Antitrust Law

The FPC has only limited authority relating to the implementation of the objectives of antitrust law. Unlike the statutory authority provided for other Federal regulatory agencies which allows them broad authority in antitrust considerations over the regulated industry,[26/] the FPC has only the limited authority provided by 16 U.S. Code Sections 824b and 824c.

The authority provides for Commission approval of certain dispositions of property and the acquisition of securities and also requires Commission approval for the issuance of securities. However this authority may be viewed, it does not rise to the level of antitrust enforcement or the exemption from antitrust laws for the regulated industry.[27/] The Justice Department and the FTC primarily enforce antitrust violations in the electrical power industry. The FPC does have some legal obligation to consider the effects of its regulation in light of antitrust laws. For example, in the issuance of securities the Commission is obligated to consider anticompetitive consequences of the issue.[28/]

Other exercises of power by the FPC also raise antitrust considerations. It has been suggested that "wheeling" of power through interconnected systems has the effect of accelerating the prospects of wholesale competition.[29/] To this extent and others, the Sherman Act[30/] and the authority under the Federal Power Act may conflict.[31/] The Otter Tail Power litigation dramatically demonstrated this confict.[32/]

Otter Tail's refusal to "wheel" power on the theory that the FPC did not have authority to order "wheeling" was held not to relieve Otter Tail of the obligation it might have to wheel power under antitrust law. Clearly the refusal to wholesale or wheel power could constitute illegal monopolization. The application of antitrust laws could thereby accomplish what the FPC cannot do directly: namely, require involuntary interconnection and wheeling.[33/]

Antitrust considerations relevant to a possible national power grid will likely involve serious policy considerations. Enforcement and application of antitrust laws by the Federal Trade Commission and the Department of Justice rather than the regulatory authority over electrical power companies (whether the FPC or some other entity) certainly allows for fragmented policy-making. Moreover, the use of corporate mechanisms for the implementation of a national power grid, without adequate consideration of antitrust implications, may also result in regulatory overlaps or deficiencies.

Federal Chartered Corporation

The legal mechanism of the Federally chartered corporation may provide yet another alternative available for the implementation of a national power grid. Federally chartered corporations have been used for a wide variety of public and governmental purposes.[34/] Such a corporation could be charged with the authority to buy and sell power, could affiliate with various electric facilities, could finance necessary physical facilities, and could generally provide by a corporate form the ability to implement many aspects of a national power grid which might be legally prohibited to present utilities.

There are, of course, many of the same legal considerations involved in this alternative as with the creation of greater Federal regulatory authority. One significant policy consideration relating to the corporate form is the question of its control, regulation and oversight.

State Utility Regulation

As can be seen from an examination of state laws, the regulation of electrical utilities, while frequently similar, is not uniform from state to state.[35/] As has already been indicated, the fact that different forms of regulation exist on a state level would not effect a preemptive exercise of Federal authority.

It might be mentioned, however, that several legal methods exist for greater conformity of state laws. Uniform laws could be enacted through the burdensome process of enactment in each state.

Federal incentives to adopt uniform regulation, such as highway trust fund requirements that eligibility for highway grants is contingent on the adoption of uniform highway laws, could be used. 36/

The most significant area of conflict would probably be raised by an exercise of Federal authority which continued to leave certain limited regulatory aspects to the states, thereby necessitating new state regulatory mechanisms.

Conclusion

That greater Federal powers over electrical generation and transmission can be exercised in a manner compatible with the Constitution is clear. In many respects the legal issues raised by any proposal for a national power grid are a reflection of the present regulatory devices used on all levels of government. It should be clear that there is already a substantial body of law, both statutory and judicial interpretation, which is applicable to the regulation of electrical power.

The consideration of the important national policy issues relating to a national power grid will necessitate full consideration of that body of law.

FOOTNOTES

1/ 16 U.S. Code Section 824a.

2/ 16 U.S. Code Section 824b.

3/ 16 U.S. Code Section 824c.

4/ 16 U.S. Code Sections 824d and 824e.

5/ __________ , Public Utilities Regulation - Jurisdiction of the Federal Power Commission: Factual Determination of Interstate Flow Required, 46 Washington Law Review 837 (1971).

6/ See generally, *Federal Power Commission* v. *Florida Power & Light Co.*, 404 U.S. 453 (1972); *Connecticut Light & Power Co.* v. *Federal Power Commission*, 324 U.S. 515 (1945).

7/ *Federal Power Commission* v. *Southern California Edison Co.*, 376 U.S. 205 (1974); *Cincinnati Gas & Electric Co.* v. *Federal Power Commission*, 376 F. 2d 506 (5th Cir. 1967), cert. denied 389 U.S. 842; *Public Service Co. of Indiana, Inc.* v. *Federal Power Commission*, 375 F. 2d 100 (7th Cir. 1967), cert. denied. 387 U.S. 931; *Arkansas Power & Light Co.* v. *Federal Power Commission*, 368 F. 2d 376 (8th Cir. 1966).

8/ See footnote 5, *supra.*

9/ 16 U.S. Code Section 824d.

10/ See, *Indiana & Michigan Electric Co.* v. *Federal Power Commission*, 365 F. 2d 180 (7th Cir. 1966), cert. denied 385 U.S. 972 (1966).

11/ *Otter Tail Power Co.* v. *United States*, 410 U.S. 366 (1973).

12/ *Id.*, at 375.

13/ 16 U.S. Code Section 824a (d).

14/ *Otter Tail Power Co.* v. *Federal Power Commission*, 429 F. 2d 232 (8th Cir. 1970), cert. denied 401 U.S. 947.

15/ See, __________ , Electric-Utility Interconnections: Power to the People, 21 Stanford Law Review 1714 (1969).

16/ S. Breyer and P.W. Mac Avoy, Federal Power Commission and the Coordination Problem in the Electrical Power Industry, 46 Southern California Law Review 661) (1973).

17/ See, ________, Blackout of Interconnected Electric Companies: Recovery and Prevention Measures, 53 Minnesota Law Review 162 (1968).

18/ United States v. Wrightwood Dairy Co. , 315 U.S. 110 (1942); Wickard v. Filburn, 317 U.S. 111 (1942).

19/ United States v. Gainey, 380 U.S. 63 (1965); Leary v. United States, 395 U.S. 6 (1969).

20/ Maryland v. Wirtz, 392 U.S. 183 (1968).

21/ Wickard v. Filburn, 317 U.S. 111 (1942);

22/ See, Federal Power Commission v. Southern California Edison Co., 376 U.S. 205 (1964), rehearing denied, 377 U.S. 913.

23/ Article VI, Clause 2, U.S. Constitution. See, Killian, The Constitution of the United States of America: Analysis and Interpretation, pages 866-887.

24/ Frankfurter and Landis, "The Compact Clause of the Constitution--A Study in Interstate Adjustments," 34 Yale L. J. 685 (1925); F. Zimmerman and M. Wendell, Interstate Compacts Since 1925 (Chicago: 1951); F. Zimmerman and Wendell, The Law and Use of Interstate Compacts (Chicago: 1961).

25/ See, Killian, The Constitution of the United States of America: Analysis and Interpretation, page 422.

26/ See, for example, the provisions of 49 U.S. Code Sections 1378-1384 regarding the authority of the Civil Aeronautics Board over merger, pooling and anticompetitive activities of air carriers.

27/ See, for example, the exception from applicability of antitrust laws provided to air carriers. 49 U.S. Code Section 1384.

28/ *Gulf State Utilities Co.* v. *Federal Power Commission*, 411 U.S. 747 (1973), rehearing denied 412 U.S. 944.

29/ ________, Public Utilities: Revision of Territories in the Electric Power Industry, 1970 Law & Social Order 76, 97.

30/ 15 U.S. Code Sections 1-7.

31/ ________, Public Utility Regulation: Wheeling and the Sherman Act, 1972 Law and Social Order 507.

32/ *Otter Tail Power Co.* v. *United States* 410 U.S. 366 (1973).

33/ See, generally, ________, Antitrust Law - Public Utilities - Power Company's "Refusal to Deal" With Former Municipal Customers Found to Violate Sherman Act. 5 Seton Hall Law Review 92 (1973); ________. Antitrust - Regulation by the Federal Power Act Does Not Immunize Electric Utility From Sherman Act Sanction Against Refusals to Deal Intended to Create or Maintain a Monopoly. 23 Drake Law Review 182 (1973)

34/ See, Poling. Corporations Chartered by Act of Congress, Congressional Research Service, Multilith 73-31A (January 5, 1973).

35/ Federal And State Commission Jurisdiction and Regulation - Electric, Gas and Telephone Utilities. Federal Power Commission (1973).

36/ 23 U.S. Code Section 120 note.

Appendix II

Comments by Interested Organizations on Congressional Research Service Study

Start with NEW ODD)- Carry

AMERICAN PUBLIC POWER ASSOCIATION

2600 VIRGINIA AVENUE NW WASHINGTON DC 20037 • 202/333-9200

OFFICERS
President STANLEY R. CASE
President-elect LOUIS H. WINNARD
Vice President CHARLES E. DUCKWORTH
Treasurer WALTER R. WOIROL
General Counsel NORTHCUTT ELY
General Manager ALEX RADIN

DIRECTORS
JAMES E. BAKER
Shrewsbury, Massachusetts
ALDO BENEDETTI
Tacoma, Washington
EARL F. BRUSH
Lansing, Michigan
STANLEY R. CASE
Fort Collins, Colorado
WILLIAM H. CORKRAN, JR.
Easton, Maryland
NORMAN E. DIETRICH
Austin, Minnesota
CHARLES E. DUCKWORTH
Garland, Texas
A. L. EDWARDS
Grand Haven, Michigan
JOHN C. ENGLE
Hamilton, Ohio
JAMES P. FULLER
Muscatine, Iowa
JAMES L. GRAHL
Basin Electric Power
Cooperative, Inc
Bismarck, North Dakota
CALVIN R. HENZE
Memphis, Tennessee
PATRICK J. HESTER
Rockville Centre, New York
WARREN D. HINCHEE
Burbank, California
W. G. HULBERT, JR
PUD #1 of Snohomish County
Everett, Washington
W. BERRY HUTCHINGS
Bountiful, Utah
ALAN H. JONES
McMinnville, Oregon
MAX E. KIBURZ
Loup River Public Power District
Columbus, Nebraska
C. D. McINTOSH, JR
Lakeland, Florida
JAMES L MULLOY
Los Angeles, California
A. J. PFISTER
Salt River Project
Phoenix, Arizona
JOHN POLANCIC
Rochelle, Illinois
V. G. SCOGGIN
Nashville, Tennessee
JAMES D SHERFEY
Bristol, Tennessee
EARL SWITZER
Macon, Missouri
J. B THOMASON
South Carolina Public
Service Authority
Moncks Corner, South Carolina
MITCHELL W TINDER
Frankfort, Kentucky
MARION R ULMER
Jonesboro, Arkansas
DENNIS VALENTINE
California Municipal
Utilities Association
Sacramento, California
DONALD VON RAESFELD
Santa Clara, California
GEORGE W WATTERS
Clark County Public Utility District
Vancouver, Washington
LOUIS H. WINNARD
Jacksonville, Florida
WALTER R WOIROL
PUD #1 of Chelan County
Wenatchee, Washington

December 31, 1975

The Honorable Lee Metcalf
U.S. Senate
1121 Dirkson Senate Office Bldg.
Washington, D.C. 20510

Dear Senator Metcalf:

By letter of December 3, 1975, you transmitted to me for comment a copy of a study of a national power grid system carried out by CH_2M Hill under contract to the Congressional Research Service. I would make the following points about the study:

The national grid report is an interesting compendium of a lot of material that has been published in other areas. The conclusions are not sharply focused, however, and as a result it would appear that one, could draw a somewhat negative conclusion as to the reports endorsement of the concept of a national grid. However, the report points up -- although not in great depth -- a number of problems that could be solved by a national grid.

1. The report points out that the diversity among systems is already largely used, but it also indicates that this diversity (which is largely sold through so-called "economy exchanges") is not shared equally among all systems in the United States. In fact, preferential treatment is given to systems which are fully admitted partners in "pools" and discriminatory treatment is given to those which are either subordinate partners of such pools or which have been eliminated from power pools because of restrictive practices. This is a gray area of transmission planning and regulatory authority which is only being overcome by difficult, tedious, and litigious processes rather than according to a national enunciation of public interest goals. A national grid should provide an apparatus and a technique for diversity exchanges which might make better public economic sense than the practices now taking place. For example, it is pointed out in the report that the "Balkanised" pool (ERCOT) in Texas has the largest unused diversity available for use in other areas and is also potentially the largest market for other regions' diversity. Nevertheless, no organized or planned arrangement for transmission interchanges exists for tapping this market, largely because of a local interest in remaining out of regulatory control.

2. The report indicates that transmission interconnections within regions have been developing in an evolutionary manner in a form which essentially accomplishes the goal of using up available surpluses and diversity and providing intra-region

reserves and reliability. It points out, however, that this does not provide for comprehensive planning in order to optimize the load and resource planning within regions, nor does it take into consideration the needs of regions adjacent to or remote from the ones in which such transmission construction is taking place. Thus, although diversities may be utilized, no one knows whether resources have been well or poorly planned for development.

3. The report does point to the fact there is no sense of national goals in transmission. The national grid that is forming ad hoc is taking place as a by-product of company-by-company planning. Such planning involves individual system loads with a means of minimizing transmission investment and maximizing opportunities to sell interim surpluses. There is no technique in use to acquire data on actual energy exchanges in a comprehensive manner. Thus, while we know from the net energy produced and sold what the overall effect of energy exchanges has been, we do not know the extent to which these have resulted from planned and optimized operations.

4. There has been no serious consideration or national planning for "fuel by wire" in harmony with our announced national goal of utilizing coal in preference to petroleum, wherever possible. The failure of the present system of individually held transmission lines to produce substantial amounts of "fuel by wire" during the Arab boycott of 1973-74 has resulted in confusing and unclear subsequent regulatory rule-making. We lack a sense of national decision that coal utilized in major plants can be shipped by wire to any national area of need at costs reasonably consistent with a national interest. The report alludes to the weaknesses of the regulatory bodies in their approach to transmission policy. It points to the inconsistent views held by various parties concerning regulatory authority to deal effectively with transmission and/or "wheeling." Obviously, a national grid would provide an apparatus for regulatory commissions to use in the best possible sense, i.e., regulation by comparison of transmission alternatives.

5. Certain public interest issues were not touched upon in this report, primarily the one concerning proper land use of transmission lines. The regulatory problem was alluded to and the report is an excellent demonstration of the fact that the national transmission system has evolved without comprehensive national planning. Individual lines are planned well with respect to individual loads and generation but with little consideration for the total impact on the nation's land resources. Surprisingly, I was not able to find in this report any concern about transmission line use of land but merely an economic analysis of transmission vs. other forms of energy transportation. (The report acknowledges that, "The environmental effect of a grid, considering land needed for transmission lines, could only be estimated after more detailed study.") Planned transmission lines designed to accommodate not only the "national grid" but also to encompass the capacity of the electric supply now being transmitted along a number of other parallel paths could greatly improve the economic use of land space.

6. If there is to be a concerted national effort to build plants in the vicinity of mines (mine mouth generation), a transmission grid dedicated to that concept should be developed for use by all segments of the power industry. This would simplify power planning and concentrate efforts on constructing coal fired plants at the most economical sites first, including most favorable sites relative to the transmission grid.

Although the report points up a number of areas which require further study, I believe the significance of giving attention to a national power grid is underscored by the report's assertion that reserves might be reduced 1 to 3 percentage points through the operation of a strong national power grid. A range of 1 to 3 percentage points (which is probably a conservative estimate) is not inconsiderable when one notes that for each 1 percentage point reduction from 1975 levels of operating reserves, the nation could realize a present value of capital savings over 10 years of $3.16 to $3.22 billion, according to the report.

Although the report states that there is "no direct justification for an accelerated effort to construct a discrete national power grid superimposed over the present and planned systems," the report acknowledges that the concept of a national power grid is not limited to a discrete grid superimposed over present and planned systems. Certainly, at the very least, some of the specific interconnections studies advocated in the report (such as the interconnection between ERCOT and SPP, and a direct current interconnection between WSCC and MARCA) should be undertaken. Also, there is ample evidence that the Congress should address itself to the legal authority of the Federal Power Commission to compel wheeling.

I believe that the report provides sufficient information, and raises enough questions, to warrant continuing consideration of the concept of a national power grid. The report itself acknowledges that, "There is not sufficient data developed within the scope of this study to present a conclusive analysis of the feasibility of additional regional interconnections or a fully developed national grid."

As you know, Congress recently approved H.R. 6669, to authorize the Department of the Interior to carry out certain feasibility studies, including an evaluation of the benefits, revenues, and costs that would result from integrating loads and resources between major river basin transmission systems by means of power interties in the 17 Western states. It seems to me that this study could explore further the concepts of a national grid as applied to a major segment of the country. With proper funding and interest, the results might be most useful.

I hope that these comments are of some value to you.

Sincerely,

Alex Radin

Alex Radin

AR/dt

EDISON ELECTRIC INSTITUTE
90 PARK AVENUE • NEW YORK 10016 • (212) 573-8700

February 17, 1976

Honorable Lee Metcalf
United States Senator
1121 Dirksen Senate Office Building
Washington, D. C. 20510

Dear Senator Metcalf

Thank you for giving the Institute the opportunity to review the report entitled National Power Grid Study, An Overview of Economics, Regulatory and Engineering Aspects, which the Library of Congress prepared for Congressman Ottinger and you.

We have carefully reviewed this issue and we oppose the imposition of a discrete national grid superimposed over present and planned transmission systems. It would result in an unwarranted expenditure of the taxpayers' money. It is unnecessary because its alleged benefits are already provided by the electric power systems of the United States, which have been built and interconnected so as to serve the electric power needs of the American people.

The report is critical of the national grid which presently exists and indicates that significant economies may be realized if various assumptions are made. Our comments on the approaches suggested are set forth in the attached document.

Sincerely yours

W Donham Crawfor

W Donham Crawford
President

Attachment

Comments of Edison Electric Institute on the National Power Grid System Study prepared for the Library of Congress, Congressional Research Services

The report is a thorough analysis of the many factors involved in the concept of a national grid. We agree completely with the study's conclusion that there is "no direct economic justification for an accelerated effort to construct a discrete national power grid superimposed over present and planned transmission systems".

We concur with the conclusion "We expect the national grid to evolve whether or not a deliberate effort is made to accelerate its development." Since this is hardly a "do nothing" approach, the report's first policy and action alternative is misleading.

As the study states, experience has demonstrated that the nation's transmission networks should be planned and should evolve in such a manner that they are flexible enough to meet load growth and to accomodate changing conditions and circumstances. Expenditures are made only as required. The study also attests to the high levels of interregional emergency transfer capability of the existing transmission networks and to the extensive future additions planned by the electric utility industry.

We concur with the study's findings regarding load diversity and its use. Seasonal diversity, as the study indicates, is already being utilized to the extent that it can be reliably predicted, while time-zone diversity is too small and erratic to be integrated into the planning of power supply facilities.

Edison Electric Institute for many years has compiled and analyzed diversity data and will continue to do so in the future. However, caution should be used in interpreting data for the years 1974 and 1975, because of the unusual economic and fuel availability conditions which existed. In our judgment, it would be premature to draw conclusions from such data with respect to possible future trends in load diversity.

The study's conclusions regarding the economic advantages available through the potential for reducing reserves as a result of a national grid are questionable, both on the basis of adhering to present standards of reliability and with a reduction is such standards. While the study gives recognition to the many complex factors affecting reserve levels, it makes a highly idealistic, but erroneous, quantification of the potential financial savings which could result from such reserve reductions. Tables 5 and 6 of Chapter 5 show the postulated effects of such savings over the period 1976-1984. It should be noted that about 70% of the savings in Table 5 and about 80% of the savings in Table 6 are shown to occur in 1976, the first year of the analysis. This may be theoretically possible, but installed generating capacity reserves could only be reduced by revising construction schedules for units that are currently planned for future years. At best, such savings would only start to appear in later years, probably in the sixth to tenth year. The savings would be relatively small in value and their "present worth" would be substantially less.

It is also interesting to note that the study emphasizes "That a reduction in operating reserves would not necessarily be an outgrowth of building a national grid." Today, interconnected systems with aggregate capacities of nearly 40,000 Mw coordinate reserve capacity planning. They are capable of attaining very nearly the maximum theoretical benefits of reducing reserve requirements through the diversity of outages of many individual generating units. Any future decrease in reserves that could be achieved by coordinating even larger areas of the country, which is the supposition of the advocates of a national grid, would be minimal and could not be justified by environmental or economic cost-benefit analyses.

The cost estimates for achieving such savings resulting from reserve reductions as shown in Tables 3 and 4 of Chapter 7 are questionable. The regional construction cost levels for generating plants, given in 1975 dollars, are too high in some instances. For example, the cost of $540 per Kw to build a coal fired plant in the ECAR area is significantly higher than the cost of such plants which actually went into operation in this region in 1975. Also, transmission costs appear to neglect substation and terminal costs, as well as the costs for other related system reinforcements made necessary by the addition of extra-high-voltage transmission. The discussion of savings resulting from reducing operating reserves by selected amounts (beginning on page 7-21) does not appear to take into consideration the costs of the increased transmission facilities and control equipment which are required to make these savings possible.

Chapter 4 includes comments on the absence of studies for reserve requirements of the nation operated as a single power pool. Considering the vast geographical spread of the United States and the many regional differences in load patterns and generating plant resources, it is unrealistic to argue the merit of such a generalized reserve determination. It can be nothing more than a highly idealized paper computation. Furthermore, the vast number of generating plants involved in this country, together with their widespread geographical separation, makes it impossible to meaningfully dispatch and operate from a single control center, as is implied by such an analysis.

The significance of the economic analyses discussed in Chapter 7 is questionable because of the lack of depth and failure to consider all factors. For example, most of the benefits cited for interconnecting the western and central section of the country are attributable to load diversity. But it appears that only the interregional connections are considered as costs and an arbitrary allowance is made for internal transmission and dispatching "to account for diversity being widely scattered."

The report discusses significant reductions in installed generating capacity if overall electric system reliability levels are reduced. In this regard, reliability priorities for selected loads are mentioned and methods to physically protect service to higher priority loads are suggested. Prior to evaluating these observations, one must consider the nature of electricity as contrasted to other energy supplies, or, for that matter, all other commodities in our society. Secondly, the impact on reliability resulting from the operation of generating, transmission, and distribution facilities must be considered.

Since an electric system must remain in continuous, dynamic balance (i.e. energy input equal to energy output), care must be taken in arbitrarily reducing generating reserve levels with the objective of attaining and accepting a lower level of overall system reliability. Depending on the electric configuration of the system, a very small operating reserve level may not be sufficient to prevent instability and could cause a cascading outage unless some type of planned curtailment of customer service is available to interrupt loads during periods of generation deficiencies. Such interruptions, to be meaningful, will necessarily involve blocks of load such as represented by entire substations. Under these circumstances, it is virtually impossible to discriminate on the basis of criticality of consumers. Such planned curtailments are essential if the integrity of the interconnected network is to be preserved.

Service interruptions at the distribution system level, on the other hand, are localized and of small magnitude. Therefore, the impact can be absorbed without adverse effects on the overall system. Transmission interruptions generally do not result in customer interruptions because of the alternate lines which exist in a network. Reliability standards are set to avoid widespread, cascading-type outages. Because of these factors, it is not possible to plan, design, construct and operate power systems with closely comparable reliability levels in generation, transmission, and distribution.

We agree with the report's conclusion that wheeling is a useful technique but should not be imposed without careful technical study of its effects. It should be noted that there is a great amount of wheeling currently taking place.

The report also refers to industry-wide resistance to the "common carrier" concept on the grounds of its constraint on flexibility of operations. Of significance in this connection is recognition of the technical constraints resulting from the fact that power flow patterns in a transmission network cannot be specified. They are the result of the physical and electrical configuration of the network, its generating sources, and the amount and distribution of loads at a given time. Therefore, short-term wheeling arrangements are only possible after careful study, while long-term wheeling arrangements must be integrated into the planning of the network. This forecloses the practicality of a "common carrier" approach to transmission.

Chapter 8 includes reference to the possible need for regulatory jurisdiction over technical aspects of the power industry. As to regulatory considerations, in general, we believe that state jurisdictions are best able to regulate the power industry as to reflect important state or regional differences. There is already evidence of a growing layer of Federal regulations which is resulting in contradictory and overlapping jurisdictions and which is adding to the lead-time for the construction of necessary power supply facilities.

We do not agree with the report's observations that changes in the structure of the electric utility industry will likely be required to further a national grid or that small electric utilities do not participate in the benefits of interconnected operations. Existing electric power systems are capable of interconnecting and strengthening the existing grids "to form a full, operating national grid" called for in the report as "a logical alternative to a superimposed system." This continually evolving electric power system, which is operated under appropriate state and Federal rate regulation, also is capable of providing economic and operating benefits to all utilities including small systems.

The majority of small electric power systems are government-owned or financed and already enjoy freedom from taxation and very favorable financing terms. They also have preference in obtaining power produced by Federal government power systems.

In addition to these advantages, small systems can share in the benefits of scale and advanced technology by purchasing power from larger systems at prices and conditions of service that are comparable to the terms under which the retail customers of these systems purchase electric power. Their equitable treatment and access to the benefits of scale and technology are assured by the Federal Power Commission, which must approve wholesale power contracts. Furthermore, the rights of small non-investor-owned systems are subject to consideration by the Justice Department. There also are opportunities for voluntary contractual arrangements among electric systems of diverse size and ownership when the potential participants can bring to the arrangements benefits which can be shared on an equitable basis. A change in the electric utility industry's structure is not needed to assure small power systems access to the benefits of scale and technology.

KEN HOLUM & ASSOCIATES
CONSULTANTS
RESOURCE DEVELOPMENT - PLANNING MANAGEMENT
(GOVERNMENT RELATIONS)

1019 NINETEENTH STREET, NORTHWEST
WASHINGTON, D. C. 20036
SUITE 200

AREA CODE 202
OFFICE: 659-8931
HOME: 829-2257

December 30, 1975

Honorable Lee Metcalf
United States Senate
Washington, D. C. 20510

Dear Lee:

Thank you for your December 3 letter which supplied me with a copy of the study of a national power grid conducted for the Congressional Research Service by CH2M Hill. I appreciate the opportunity to offer a few observations.

(1) Study 190 conducted by the power marketing agencies of the Department of the Interior during the Johnson Administration and released to the public for information and comment in February of 1968 was more limited in scope (it studied the interconnection of utility systems in the west and between the western and central areas of the country) but done in more depth and detail. Study 190 analyzed 12 plans for the interconnection electric utility system west of the Mississippi and found them all economically feasible with benefit-cost ratios ranging from 1.3:1 to 1.9:1, using the Federal financial criteria applicable at the time, i.e., 3.25 percent interest and 50-year payout.

(2) The Library of Congress Study correctly observes that many utilities--mostly smaller ones--do not share the benefits of the evolving interconnected system operation. A national power grid would correct this inequity and contribute substantially to the continued existence of a pluralistic electric system for the benefit of consumers.

(3) The National Grid Bill you have sponsored contemplates the creation of regional publicly owned bulk power supply organizations. The study notes that the concept has merit and that it warrants serious public consideration. However, the study does not evaluate the concept and consequently it does not and cannot consider the economic and evironmental advantages of this basic concept and the resulting ability to supply all utilities with bulk power from large, economic and strategically located generating stations.

(4) The Study explores and comments on the regulatory problems that would result from the creation of a national power grid. It might be appropriate to consider the need to revise our regulatory agencies and procedures as a benefit rather than as a disadvantage.

In summary, it seems to me that the Study leaves the reader to decide whether the broad public interest will best be served by an evolving national grid that does not adequately protect small systems regardless of ownership and without regional bulk power supply corporations and a national grid as contemplated by the legislation you have sponsored. I prefer the Metcalf approach.

With kind personal regards, I am

Sincerely,

Ken Holum

H:k

Missouri Basin Systems Group
no. 6, 10210 west 26th avenue, lakewood, colorado 80215 • (303) 232-3663

January 5, 1976

Senator Lee Metcalf
United States Senate
Committee on Government Operations
Washington, DC 20510

Dear Senator Lee:

I am writing to transmit my views and those of my associate, Wayne Stafford, of the CH2M National Power Grid System Study commissioned by the Library of Congress, which you were kind enough to send me. Previous studies of the feasibility of interregional interconnections of this type have found, with their varying assumptions and predispositions, that EHV or UHV interconnections integrating at least the Midwest with the Western U. S. (the two major interconnected systems in the country) were both feasible and infeasible. The studies I have in mind are Transmission Study 190 conducted by the Department of the Interior in the late 1960's, and the WUS-CUS (Western U. S.-Central U. S.) Study, an analysis conducted by a group of utilities, including representatives of Missouri Basin Systems Group, in 1973.

After reviewing the CH2M Study, its review of the WUS-CUS Study, and the WUS-CUS Study itself, I believe that economic feasibility for one or more direct current (DC) interconnections between the Western and Midwestern U. S. can be established today.

In naming MBSG as a signatory of the WUC-CUS report I should point out that MBSG study participants had great concern about the legitimacy of some of the study's assumptions and debated at length before deciding to sign the final report. They did so because they believed there was some net benefit in the report. Although there seemed to be a predisposition by most of the WUS-CUS Study participants to find against economic feasibility for interconnections studied in the report, I would point out that the report found approximately 0.86 benefit/cost ratio of the DC interconnection studied. This despite a number of debatable economic assumptions which weighed against a higher benefit/cost ratio. These assumptions included (1) that 68% of the facilities studied would be investor-owned, thereby making fixed costs considerably higher than if the facilities were federally-owned, or owned by consumer-owned utilities; (2) that the DC line would have to be 1900 miles in length; and (3) that the report should not evaluate economic benefits lumped under the heading of "Intangible Benefits."

The CH2M Study reassessed the WUC-CUS Study, in some respects, arriving at a benefit/cost ratio of 0.91. Other problems were still not addressed by the CH2M review, however. For example the 1900 mile length required for the DC line, was not questioned by CH2M (except at page 2-3, where CH2M concedes the lines might be only 1500 miles long). Neither was the assumption that the line would be principally financed by investor-owned companies questioned. Both matters seem to me clearly questionable and would importantly affect the benefit/cost ratio.

Considering that the DC interconnection, even analyzed on this basis, achieved a 0.91 benefit/cost ratio, I certainly agree with the CH2M conclusion stated at page 7-16 that "a more detailed examination of this possible major interconnection is justified." If such a study is undertaken, I would urge that it also consider, in relation to the Western U. S.-Central U. S. interconnection, that it would provide emergency transfer capability and other "intangible" benefits to the two major interconnected systems in the country, which would not be provided by alternative interconnections.

In general, as indicated by the comprehensive list of additional studies suggested by CH2M on pages 2-8 through 2-10, it is clear that the instant study is not a comprehensive one of the type required to analyze whether certain EHV or UHV interconnections, or a national network of them, are economically feasible or otherwise in the national interest.

I would also be cautious about interpreting the CH2M study findings too negatively. Most of the findings seemed to me to be equivocal, which seems appropriate in light of the complexity of the subject matter. Note, for example, the statement at page vi of the Summary that "if a full national power grid system could be developed, some relatively small reduction in the amount of generating capacity reserves carried by the nation's electric utilities may be possible. The effect of this lowered reserve level is not likely to permit a reduction in an average residential electric bill of more than about 3%." Three percent of the national electric bill is likely to be quite a large number, the savings of which could quite likely justify a network of DC interconnections carefully planned to accomplish identified purposes. CH2M's choice of words in dismissing the impact of the lowered reserve level suggest that similar caution be used in examining such statements in the report that "there is very little usable load diversity among electric systems that is not already being utilized by existing interconnecting systems" (page 2-1); etc.

It seems to me that the CH2M Study falls too willingly into the trap most utility analyses of this question have set over the past several years, by posing construction of an accelerated effort to construct a discrete national power grid [as being] "superimposed" over the present and planned system. This is an unreasonable statement of the problem. Why do the authors assume that the national power grid will be planned without intelligent and careful reference to the existing and planned systems? Would not the authors concede that establishment of a national power grid could reduce the need for investments by utilities to develop "the transmission network that is now evolving?" Would not the authors concede that the network that is now evolving is being planned in a smaller frame of reference, to meet the more limited needs of the individual utilities? Other than the Pacific Northwest-Southwest interties are the authors aware of any other transmission planning among utilities even approaching the scope contemplated by a national power grid? The implication throughout Chapter 2 of the CH2M report is that electric utilities take the same considerations into planning in their rather more limited scope as would be encompassed in a broader look at the problem. This does not square with reality.

For example, the interregional "interconnections between WSCC utilities and Mid-Continent . . . utilities (page 2-2) which were referred to as having been operational in the past were simply interconnections of one Bureau of Reclamation system with another to achieve some limited energy transfers. They did not represent efforts by utilities generally in those two regions to establish interconnection, nor are there such efforts which the authors could point to today. Throughout the report I believe the authors have overstated the efforts of the industry toward broad and intelligent planning and therefore understated the possible usefulness of a carefully undertaken effort to examine the problem openly from a multi-regional or national point of view.

The companion analyses entitled "A National Grid System and the Environment" and "The Legal Issues Related to a National Power Grid" seem to be very often irrelevant treatises too general to be useful. The environmental paper, for example, spends most of its 18 pages discussing the environmental consequences of power production and transmission today, rather than the special environmental consequences of a national power grid system (and its relation to business-as-usual) which is barely addressed at all. The legal paper takes only one-half page of its 14 pages to discuss the federally chartered corporation as the instrument to establish the national power grid. This is the principal method which has been suggested for establishment for such a grid, and should, I think, have been the principal subject of the paper, rather than a near footnote.

In summary, the CH2M study and its companion papers seem to me a very "safe" analysis, reflecting the national indecision about whether a federally-imposed planning and operating network would or would not be beneficial. As a relatively young veteran of ten years in regional power planning I am convinced that present industry efforts to plan facilities to meet the public interest are not realized because of corporate fears and jealousies and because of the inherently narrow scope of planning which results from a system which places decision-making in the hands of literally thousands of electric utility systems. Individual corporations -- especially the largest of them -- are bound to be jealous of their prerogatives and attentive most to the particular needs of their constituencies.

Had planning of the national highway system been left to such a collection of groups, we would never have an interstate highway system today.

Wayne Stafford is a registered Professional Engineer in the employ of the Missouri Basin Systems Group. His independent analysis of the CH2M Study, which I have reviewed, is also enclosed for your consideration. It points out some internal inconsistencies in the CH2M report itself. If we can be of additional help please feel free to call on us.

Sincerely,

Robert O. Marritz
Executive Director and Counsel

Enclosure

Notes on the review of the "National Power Grid Systems Study and Overview of Economics Regulatory and Engineering Aspects" for the Library of Congress Congressional of Research Service, November, 1975.

This study is accurately described at page v as "not a feasibility study, but an overview pointing the way to further examination of this important aspect of the national energy supply program."

Although the study at page v finds that "If there is anything more than 'do nothing' alternatives undertaken, regulatory agencies and transmission - operating entities should be structured to provide multi-state jurisdiction." However, a proportionately small proportion of the study reported herein addresses this issue. Further no attempt at defining the cost (or benefits) attributed to these regulatory proceedings is included in the evaluation of example interconnection studies used by the study; the ERCOT-SPP interconnect and the Western U. S. - Central U. S. Study.

At Page 1-4 the study identifies for a national power grid system the alternatives:

1. Do nothing.
2. Encourage extension and strengthening of existing power networks.
3. Develop regional and regulatory operating agencies to plan, construct,operate and regulate the nation's bulk power transmission system.
4. Create a Federal agency to plan, construct and operate, regulate the nation's bulk power transmission system.

Although these planning alternatives are stated to meet the framework in which a reader should evaluate issues addressed in the study, we find no comparisons of these options for a national bulk transmission system or any lucid conclusions relative to these alternative strategies. The study spends a great deal of time in a tutorial vein attempting to educate the reviewer instead of accomplishing an overview or analysis.

The study admits that it is not possible to quantify many of the aspects of benefits, even though significant conclusions based on benefit to cost ratios have been presented. For example, on page 3-7, the study notes "There is no special measure of the magnitude of short term load diversity in the U. S. nor of the amount now captured and sold or interchanged by utilities. Such interchanges and sales are common practice in electric utility industry . . . The amount of power interchange sold for "economy" energy cannot currently be determined." The study continues at page 3-30 to note that "the only diversity that would be of value to the industry would be that which yields economy energy interchanges . . . the production of energy on the short term basis by a low cost producer for sale to another producer whose best alternative for the power production would cost more." This must make study conclusion questionable at the least since this important use for diversity was an "immeasurable quantity" and not included in the benefit determinations used later in the study to exemplify the apparent diseconomy of regional interties.

The study concludes at page 4-21 "Thus, we believe that the existence of a national grid would not allow utilities large reduction in reserves on an overall national basis -- it is likely that utilities' financial requirements will have a much greater impact on future utility reserve levels and reliability of service than a national power grid would." However, the overview study does not examine the effect of these "financial requirements" to establish the reasons for the conclusion stated. At the same time on page 4-1 the study notes "the primary benefits of interconnection between systems include a reduction in the amount of generating reserves that must be maintained and improvement in system reliability."

However, the study determination of cost benefit relationships appears to predicate nearly all of its conclusions on possible cost (capital) savings due to reduction of reserve requirements.

Although the study concluded at page 4-21, the existence of a national grid would not allow utilities large reductions in reserves on an overall national basis, and that reserve requirements was more likely to be determined by financial requirements, the study methodology is confusing and inconclusive when at page 7-2 the study further reports "lacking in load diversity justifications for specifying a full and discrete grid, we analyzed the possible capital savings from reducing generation reserves. The assumption underlying these policies is that the establishment and operation of the national grid may allow the amount of the operating reserves to be reduced to a national average of about 15-18% annual peak load without reducing reliability. The assumption is generalized and applied uniformly to all electric power systems in the nation." Thus, the study tends to look toward the measure of capital savings as the motivation for the system although it later concludes that such reduction reserves is unlikely.

The study has admittedly addressed an extremely complex and interrelated set of data and issues in order to examine the national transmission grid question.

However, the study seems inconclusive and incomplete in the accomplishment of objectives stated for itself. The scope of the study seems to have become confused or evidenced by excessive generalized discussions about and definition of terms and factors commonly appreciated by utility engineers and managers.

This study should not become the key stone rationale for rejecting the concept of a national grid system. It is not clear that the "national grid system" must necessarily include the UHV overlying interconnections (765 kv or above). No attempt is made to assure the benefits of national coordination of the 114,000 miles of 345 kv class bulk transmission are "planned" by utilities between 1973 and 2000. The limitation of a national grid interconnect to 765 kv and above seems to be unnecessarily narrow and somewhat capitulating to state in effect that no benefits could accrue from joint planning, pooling and cooperation among utilities through the end of this century.

At page 7-19 the study seems to recognize some of its shortfall and inconclusiveness as it states "An alternative approach to an evaluation of economic considerations related to a national grid is to look first at broad estimates of potential as possible savings that may be related directly or indirectly to a grid. The estimates may be used on a basis for estimating the amount of capital that could be used in alternate investments that would assist in achieving the assumed potential savings."

At page 7-20 the study states "Excepting on ERCOT-SPP interconnection, and possibly a WSCC-MARCA dc interconnection, it appears that all major interconnections that are economically and technically feasible to operate are now being used to the fullest level currently economically attainable. New interconnections are being planned and constructed as needs and feasibility evolve". However, at page v the study notes regarding benefits of interconnections that "many utilities, mostly smaller ones, still do not participate in these benefits." Thus, it is suggested that the study exudes a bias toward allowing large utilities to continue to dominate the bulk power industry and reap benefits which in many cases are not traceable due to a lack of proper legislation and accounting procedures.

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

2000 FLORIDA AVENUE, N.W. · WASHINGTON, D.C. 20009 · AREA CODE 202, 265-7400

March 3, 1976

Honorable Lee Metcalf
United States Senate
Committee on Government Operations
Washington, D.C. 20510

Dear Senator Metcalf:

We are pleased to respond to your request for comment on the study of a national power grid system performed by CH2M Hill under contract to the Congressional Research Service.

In our judgement the report is a well written document. It appears to provide a generally comprehensive analysis of some of the factors and problems associated with the development of a national power grid.

In the reviewing process, we discussed the report with a number of engineers who are expert in the field of system engineering, particularly as they relate to the development of regional interties in the Western United States. These discussions have uncovered a number of specific areas which in our view could be expanded upon.

The WSCC area, for example, due to the broad geographic area covered should have been divided into separate subregions for the purpose of the diversity analysis. Furthermore, the diversity analysis does not include an examination of diversity between ERCOT and other regions. However, the report does recommend that a definitive study of interconnections between ERCOT and SPP be made. The ERCOT area has the highest summer peak in relation to its winter peak. We recall that study 190, carried out by the Department of Interior Power Marketing Agencies in 1968, under the Direction of the then Assistant Secretary for Water and Power, Ken Holum, also indicated the potential of interconnecting the ERCOT region with the Pacific Northwest because of the seasonal diversity. We are not aware of any studies updating the relative cost of the proposed HVDC line between the Northwest Power Pool and ERCOT. Since capital cost and fuel cost (except for nuclear fuel) have increased many fold since 1970, we would be interested in learning if interconnections such as the proposed HVDC line might now be justified. Also, the report states that there is a continuing nationwide trend toward summer peaks, but does not discuss those areas where increasing winter peaks are projected. These areas would include the Northwest, the TVA area and the Northeastern part of the country.

One of the interesting observations the report makes is that further studies should be undertaken on the feasibility of a transmission line between WSCC and MARCA. We gather from the report and we believe it to be true, that there is no overall national effort to bring about the construction of those interconnections which would result in a strong unified, interconnected power system throughout the continental United States.

In the main, the existing nation-wide grid has resulted from the planning by individual companies or power systems such as that of the Pacific Northwest, the Tennessee Valley Authority and some of the adjacent utilities, the American Electric Power System, the California Power Pool and a few others. What we believe is really needed is a comprehensive study aimed at the development of a power grid capable of moving large blocks of electricity across the country to meet load requirements in a reliable and economic manner.

NRECA's position on interregional interties is stated in the following resolution which was unanimously accepted at our 34th Annual Meeting at Anahiem, Califronia on February 5, 1976:

> We reaffirm our support of development of a power grid capable of moving large blocks of electricity across the country as may be required to meet load requirements. The various segments of the system should be owned and operated by individual electric systems or voluntary combinations of such systems without limitation as to type of ownership, and in such manner as to preserve the pluralistic character of the industry and the integrity of individual participating systems. The capacity of the power grid so established should be planned so as to accommodate the needs of all systems desiring to participate in its utilization. We urge a comprehensive systemwide study of transmission and generation for the entire country with full participation of the federal, private and public generating utilities to develop a master plan of needed interconnections to strengthen interregional interties.
>
> We further urge that the Federal government assume leadership in developing such a master plan of needed interconnections to promote the reliability of continuity of service throughout the United States in the interest of national safety and security.

In closing we would urge the Congress to provide the necessary funds and take whatever other action that might be required to achieve this objective.

Sincerely yours,

Robert D. Partridge
Executive Vice President and
General Manager

RDP/apu

R. W. BECK AND ASSOCIATES
ENGINEERS AND CONSULTANTS

PLANNING
DESIGN
RATES
ANALYSES
EVALUATIONS
MANAGEMENT

400 PRUDENTIAL PLAZA
DENVER, COLORADO 80202
TELEPHONE 303-292-0270

SEATTLE, WASHINGTON
DENVER, COLORADO
PHOENIX, ARIZONA
ORLANDO, FLORIDA
COLUMBUS, NEBRASKA
WELLESLEY, MASSACHUSETTS
INDIANAPOLIS, INDIANA

FILE NO.

December 18, 1975

PERSONAL

The Honorable Lee Metcalf
United States Senate
Committee Operations
Subcommittee on Reports,
Accounting, and Management
Washington, D. C. 20501

Dear Lee:

I appreciated receiving the CH2M report on the National Grid and your letter request for my comments. I must of necessity answer your letter on a personal basis as the Engineer-Author of the report is a personal friend of long standing - we worked together at Bonneville.

In my opinion the author has highlighted the problem areas for which data and information are just not available for analysis. Through his use of Consultant Allan J. Schultz, the author brings into the study most of the fundamental reservations that the private utility sector has toward a National Grid. Through Consultant Lee C. White, the legal grey zones of state and Federal legislation are fully expressed. In summary CH2M had done a good job of bringing together in one up-to-date volume, in a reasonably objective manner, the matters that need resolution before Congressional Committees will be able to get to the core of the problems facing the development of a National Grid. As a by-product, the report shows the urgent need to develop a National Energy Policy, for the electric industry cannot afford to make major decisions on the basis of the uncoordinated planning that is now taking place. With respect to the specific topics listed in your letter, I have the following comments:

Time Zone Diversity

Neither the utility industry nor FPC has ever been organized to gather data with which to make a thorough analysis for the reason

DEC 20 1975

that all have been basically unsympathetic to the idea of a National Grid. Texas apparently has boycotted all efforts to include their loads and resources. The Author (pg. 4-21) has some concern whether a computer does exist today that could make a national time zone diversity study. We suggest that an inquiry be made of the General Electric Co. to determine whether, through the use of regional grid system equivalents, its 6000 bus computer could attempt a nationwide study across three time zones.

Seasonal Load Diversity

While it appears that a sizeable amount of Seasonal Load Diversity is being utilized by and between interregional power pools, it is not clear that the ultimate has been accomplished. First, the State of Texas is isolated. Certainly, the pressures of the energy crisis will eventually bring the Texas utilities into fold. It must be timely to consider a second 1500 MW diversity exchange between TVA and the S. W. Power Pool. The Pacific N. W., Pacific S. W. second intertie line is again under study as seasonal diversities have already loaded up the present North-South interties in that region. If present domestic consumers using oil and gas for heating, convert to electric heating as has been projected by Westinghouse, we have an entirely new "ballgame" as far as seasonal diversities are concerned. This area therefore needs continuing study.

Regional Reserve Pools

The industry continues to expound the theory that "voluntary efforts" to increase interregional tie lines will eventually provide the same results as could be accomplished by a National Grid. Having knowledge of the in-fighting that goes on in the utility industry, which many times results in frustrating coordinated planning, we are not certain that opimum results on reserve sharing have been achieved. Arguments persist that reserves can be different for different geographical areas. With the recent "coal by wire" effort to more midwestern coal-fired generation to

New England during the oil embargo, it should be reasonably clear that this was a near fiasco and that FPC must take a stronger position in such matters for we cannot ask the OPEC Nations to stand by on future oil embargos or price increases while our electric industry debates among themselves what reliability standards should be used between regions throughout the U. S. An organization known as NERC is slowly working toward more uniform reliability standards, but this voluntary effort will leave the Nation vulnerable in the future if we must depend on purely voluntary efforts. We have been counting on improved administration of the Nation's present voluntary power pools by FPC, as the pooling agreements must be filed with that regulatory agency. The initial decision of the FPC Administrative Law, Judge on the NEPOOL Agreement is very disappointing and unless a better understanding of power pooling and reserve sharing responsibilities is achieved at FPC, the voluntary interconnection program now so ardently advocated by FPC, will be a real disappointment . Similar briefs are expected on the KIP and MAPP cases. If FPC does not accept its regulatory responsibility over power pools, Congress may have to put more teeth in the FPC Act or move forward on Legislation for a National Grid.

Improved Load Factors

It is recognized that "load management" now offered as a proper program during an energy crisis will improve system load factors. It is further recognized that improved load factors will reduce load diversity. However, as previously discussed, the substitution of energy fuels for space heating and the new peak responsibility rate making policies can have an effect on system load factors that are thus far unpredictable. We do, therefore, not have any opinion on the probable effect of load management on system diversities and urge continuing study on this item.

Reduction of Overall Reserves

The author of the CH2M Report concludes that overall generating reserves can be reduced to 1 to 3% through the use of a National Grid. This is the first time that we have noted any technical prediction on this most controversial area. Perhaps refined studies, when the necessary hourly load data is available, will show higher reserve savings. There are however other factors that have, as far as we can learn, not been evaluated. For instance, in the interest of oil and gas conservation, the Congress or some responsible Federal agency may find that coal energy must be imported to one or more of the regions. Present intertie capacity is limited for such purposes, as is indicated by the 1973 "coal by wire" program for New England which literally "fell on its face". Environmental considerations may show that for health reasons, generation should be reduced in the populated areas in the Eastern part of the U. S. during weekly periods of air inversion. To the best of our knowledge EPA has not given consideration to this possible use of increased regional intertie capacity for power transfers. Of course, the real problem is how will the costs of power transfer between regions be assessed when the purpose is purely environmental. This same question of allocated costs is associated with the "coal by wire" program.

Trend toward Summer Peaks

While the trend in the electric industry is toward summer peaks, this situation may be changed by the National Policy on conservation of oil and gas. This matter has been previously discussed and at this time, information and data are not available to even forecast a reliable trend. This matter surely merits further consideration.

General Comments

The Author of the Library of Congress Report, FPC, SEC, and State Regulatory Commissions apparently are depending on voluntary effort to solve the nation's energy problems and more particularily the supply of electric energy. The following two paragraphs are copied from a review that I made on a similar report in 1973 for other interested parties.

"All factors considered, the "evolutionary approach" to utility development, which the authors so ably outline, may have been adequate for utility expansion programs in the past. We are of the opinion that the future development of the Nation's electric system to meet the demands by the year 2000 goes beyond the capability of individual utilities or small groupings of utilities who, for one reason or another, may find joint planning for generation and transmission advantageous. Major energy centers, with as much as 25,000 MW, which the authors suggest, as well as the potential 95 GW of geothermal resources in the West, require the fullest efforts of all utilities working together. Power pooling must, in our opinion, do more than review the reliability aspects of announced plans which the pool members developed individually. Power pooling must embrace joint planning to meet the full needs of all utilities, whether public or private in nature. To continue the quest for scarce fuel, right-of-way and water supply for the proposed energy centers on a separate, uncoordinated individual basis will no longer be realistic.

In the event that a National Energy Policy would call for the development of major generating complexes and expanded regional transmission grids, as described by the authors, it is doubtful if the existing multitude of large and small utilities can be expected to successfully cope with such a major undertaking. It would appear desirable to consider the establishment of regional generation corporations owned and controlled by all the utilities of each region in proportion to individual load demands. However, absent such a coordinated approach to the development of major energy centers the alternative choice is a Federally charted, publicly financed corporation. This alternative has already been proposed in bills offered by members of the Congress of the United States.

I summarized my review of a 1973 report on "National Power Policy" for another interested party in the following manner.

> "The authors state, 'Before National Policy is determined, it must be clear that the required technology will be available to satisfy the conditions specified'. "This, in our opinion, is too conservative an approach for a dynamic electric industry. To push technology, it will be necessary to establish some reasonably "far-out" National goals, otherwise the industry will not be challenged to the full extent of its inherent capability. Many of the problems now facing the

> industry are the result of the lack of long-term goals, objectives and established guidelines. In our opinion, policy should lead, not follow or parallel, technology.'

The foregoing conclusion is reached after a review of the Library of Congress Report on a National Grid. It may be too much to expect that the staff of interested Congressional Committees can master the many highly technical aspects that are necessary to hold meaningful hearings on a National Grid Bill for such a Bill must of necessity be tied to the development of a National Energy Policy. It is my recollection that in the early 1930's, President Roosevelt appointed a Special Natural Resources Commission to make positive recommendations on a Federal Power Policy. Fort Peck, BPA, and perhaps TVA were outgrowths of the early efforts of that Commission. So it is now timely, in our opinion, to give consideration to the appointment of a special commission after the 1976 general elections to develop a National Power Policy, including consideration of a National Grid. By that time the citizenry will be sufficiently informed to realize that a National Energy Policy, which may involve a National Power Grid is a vital necessity to the well being of our Nation.

Our staff will continue to review the Library of Congress Report and in a few weeks, I expect to send along some supplementary comments. We do appreciate that, with your otherwise heavy work load, you continue to be interested in the public interest aspects of the electric power industry.

Kind regards.

Bill Trommershausen

W. E. Trommershausen

WET:jb

APPENDIX III

S. 1208—A Bill To Improve the Nation's Energy Resources

94TH CONGRESS
1ST SESSION

S. 1208

IN THE SENATE OF THE UNITED STATES

MARCH 17 (legislative day, MARCH 12), 1975

Mr. METCALF (for himself, Mr. ABOUREZK, Mr. HATHAWAY, Mr. HUMPHREY, Mr. McGOVERN, Mr. MANSFIELD, and Mr. MOSS) introduced the following bill; which was read twice and referred to the Committee on Commerce

---

A BILL

To improve the Nation's energy resources.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "National Electrical Energy Conservation Act of 1975".

Title I—National Power Grid and Regional Bulk Power Distribution

SEC. 101. DEFINITIONS.

For purposes of this Act:

(1) The term "National Grid" means the National Power Grid Corporation, established by section 102.

II

(2) The term "National Board" means the Board of Directors of the National Grid.

(3) The term "regional corporations" means a regional bulk power supply corporation established by the National Grid under section 103.

(4) The term "corporation" means the National Grid or any regional corporation.

(5) The term "regional board" means the board of directors of a regional corporation.

(6) The term "region" means a bulk power supply region established under section 103 (a) (1).

(7) The term "electric utility" means any person or public agency whose functions include the sale of electric power.

SEC. 102. NATIONAL POWER GRID CORPORATION.

(a) There is created a body corporate by the name of the "National Power Grid Corporation" which shall establish and operate a national power grid system. The National Grid shall have a Board of Directors, which shall consist of three members appointed by the President, by and with the advice and consent of the Senate, in accordance with section 202, and which shall direct the exercise of all of the functions of the National Grid.

(b) The National Grid shall establish and operate a national power grid system consisting of electric power generating facilities, and a system of very high voltage transmission lines which, to the extent practicable shall interconnect such generating facilities and the transmission systems of each regional corporation. Such system may be established by constructing generating facilities and transmission lines, or by acquisition of existing facilities and lines under section 105, or both.

(c) (1) The National Grid shall contract to sell electric power to regional corporations at rates which shall be regional throughout the United States and which shall be set at the lowest possible level consistent with sound business principles and the environmental protection requirements of section 201, taking into account the charges necessary to pay the operating expenses of the National Grid (including depreciation) and to amortize the indebtedness of the National Grid.

(2) The National Grid shall provide base load, peaking, or other power to regional corporations to meet requirements of which the National Grid has at least 10 years notice. Any notice of requirements under this paragraph shall be accompanied by an offer to contract for the required power.

(3) The National Grid is authorized to purchase for resale by the National Grid surplus electric power generated by any electric utility on schedules and at rates agreed upon with such electric utility.

SEC. 103. REGIONAL BULK POWER SUPPLY CORPORATIONS.

(a) Subject to section 105(a) (2), the National Grid shall establish by regulation—

(1) a number of bulk power supply regions which in the aggregation shall comprise the entire United States, and

(2) a regional bulk power supply corporation in each such region.

(b) Each regional corporation shall have a board of directors which shall be composed of three members from the region but each from a different State appointed by the National Board with the approval of the President in accordance with section 202, and which shall direct the exercise of all of the powers of such regional corporation. A member of a regional board may be removed by the National Board for cause (including failure to carry out any order of the National Board issued under subsection (f)).

(c) (1) (A) A regional corporation shall be the exclusive marketing agency for the National Grid within the region for which such corporation was established. Any electric utility, publicly or privately owned, may enter into a contract for services with a regional corporation. A regional corporation shall sell electric power to any electric utility the needs of which it has adequate notice except in cases of failure of such utility to meet its financial obligations, on proof of fraudulent application, or because of willful failure of such utility to comply with wheeling orders under subparagraph (B) or other requirements of such regional corporation.

(B) A regional corporation may not enter into a contract for services with any electric utility unless such utility agrees to permit (at such times and to such extent as such corporation may order) the use of its excess transmission capacity for the purpose of wheeling power from facilities of such corporation or of the National Grid to load centers of other electric utilities contracting to purchase electric power from such corporation.

(2) Any transmission lines of any agency the facilities of which are transferred to the corporation under section 105(a)(1) may be transferred by the National Grid to the regional corporation for the region in which such lines are located and shall be operated by such corporation. Each regional corporation shall obtain such transmission capacity, in addition to the capacity acquired under the preceding sentence, as may be necessary to sell electric power generated by the National Grid to each electric utility in the region, and to transmit to National Grid transmission lines such electric power as the National Grid may purchase from such utilities. A regional corporation may obtain such addi-

tional capacity (A) by lease of or contract for all or part of the capacity of existing transmission lines of electric utilities, (B) by modification of existing facilities of electric utilities, or (C) by construction of new transmission lines by such regional corporation. Any excess transmission capacity of a regional corporation may be made available to electric utilities on a contract carrier basis.

(d) Electric power marketed for the National Grid by the regional corporation shall be sold at a rate equal to the regional rate established by the National Grid under section 102 (c) (1), plus a transmission rate charged by such regional corporation. Such transmission rate shall be set at the lowest possible level consistent with sound business principles and the environmental protection requirements of section 201, taking into account the charges necessary to pay the operating expenses of the regional corporation (including depreciation) and to amortize the indebtedness of the regional corporation.

(e) A regional corporation shall have the authority to issue bonds in accordance with section 206, but such bonds shall not be guaranteed by the United States unless issued with the approval of the National Board.

(f) Any person aggrieved or adversely affected by any action of a regional corporation may obtain administrative review of such action by the National Board. The National

Board may, on the basis of such review, order the regional board to take appropriate remedial action. The final decisions of the National Board shall be subject to judicial review in accordance with the provisions of chapter 7 of title 5 of the United States Code.

SEC. 104. RESEARCH AND DEVELOPMENT.

(a) The National Grid shall carry out a program of research and development in the area of electric power generation and transmission. In carrying out such program, the National Grid—

(1) may conduct research and development activities directly or through contracts with any person or public agency,

(2) shall coordinate its activities with those of the Energy Research and Development Administration, and to the extent practicable with those of other public and private agencies, and

(3) shall develop priorities for carrying out such program.

In developing priorities under paragraph (3), the National Grid shall give preference to environmental protection and land use research including, but not limited to, underground high voltage transmission technology, sulfur oxide control, and other technology to improve the performance of fossil fuel plants, development and demonstration of utility corridors, development and demonstration of improved methods for disposing of waste heat, and development of alternative methods of electric power generation (including, but not limited to, solar power, wind power, hydropower, biochemical conversion, thermonuclear fusion, magnetohydrodynamics, and fuel cells).

(b) (1) The National Grid shall expend at least 2 percent of its revenues in each fiscal year to carry out the program under this section.

(2) There are authorized to be appropriated to the National Grid for each fiscal year to carry out the program under this section an amount equal to (A) $250,000,000 less (B) the amount the National Grid is required to expend under paragraph (1) to carry out such program.

SEC. 105. TRANSFER OF CERTAIN EXISTING FEDERAL-OWNED FACILITIES.

(a) Effective 180 days after the date of enactment of this Act:

(1) There are transferred to the National Grid all electric power generating and transmission facilities of the following agencies:

(A) Bureau of Reclamation.

(B) Army Corps of Engineers.

(C) Southwestern Power Administration.

(D) Southeastern Power Administration.

(E) Bonneville Power Administration.

(F) Alaska Power Administration.

(2) After amortization, hydroelectric power projects, together with associated Federal transmission facilities, which are transferred to the National Grid under this subsection shall provide financial assistance to water resource development, the reclamation fund, and the basin accounts, in accordance with the laws and procedures under which they were authorized.

(3) The Tennessee Valley Authority shall be designated as the regional corporation for the region consisting of the area in which it operates on the date of such designation.

(b) Title II of this Act shall not apply to the Tennessee Valley Authority

Title II—General Provisions Applicable to National Grid and to Regional Corporations

SEC. 201. ENVIRONMENTAL PROTECTION.

(a) Each corporation shall be subject to Federal, State, and local environmental standards. For purposes of this subsection, the term "environmental standard" means a law or regulation prescribing a standard or limitation for the purpose of control or abatement of air or water pollution or for the purpose of some other aspect of environmental protection.

(b) (1) Prior to applying to any public agency for authority to construct any proposed facility, the corporation which proposes to construct such facility, shall hold a public hearing, after adequate public notice, and shall allow interested persons to submit comments on such proposal.

(2) Each corporation shall treat all decisions regarding the siting and design of facilities as a significant aspect of land use planning in which all environmental, economic, and technical issues with respect to a facility should be resolved in an integrated fashion. In the resolution of these possibly competing demands such corporation shall give all possible weight to the protection of the environment.

(c) This section shall apply to the Tennessee Valley Authority.

SEC. 202. BOARDS OF DIRECTORS.

(a) Of the members appointed to the board of directors of any corporation, one member shall be representative of the interests of privately owned electric power companies, one member shall be representative of the interests of publicly or cooperatively owned electric utilities, and one member shall be representative of the interests of consumers. Not more than two members of any board may be members of the same political party. Not more than two members of the national board may reside on the same side of the 100th meridian.

(b) (1) Members of the board of directors of each corporation shall be appointed for terms of 6 years, except that the terms of office of the members of any such board first taking office after the date of enactment of this Act, shall expire as designated by the President (or the National Grid in the case of members of a board of a regional corporation) at the time of nomination, one at the end of the second year, one at the end of the fourth year, and one at the end of the sixth year, after such date. A successor to a member of a board shall be appointed in the same manner as the original member and shall have a term of office expiring 6 years from the date of the expiration of the term for which his predecessor was appointed. No member may be appointed for all or part of more than two terms.

(2) The members of the National Board first appointed shall be deemed the incorporators of the National Grid and the incorporation shall be held to have been effected from the date of the first meeting of the National Board.

(c) Any member appointed to fill a vacancy in a board occurring prior to the expiration of the term for which his predecessor was appointed shall be appointed for the remainder of such term. Vacancies in a board, so long as there shall be two members in office, shall not impair the powers of such board to execute its functions, and two of the members in office shall constitute a quorum for the transaction of the business of such board.

(d) The chairman of each board shall be elected by the members thereof.

(e) Each of the members of the National Board shall receive compensation at the rate provided for level II of the Executive Schedule (5 U.S.C. 5313), to be paid by the National Grid. Each of the members of a regional corporations board shall receive compensation at the rate provided for level IV of the Executive Schedule (5 U.S.C. 5315), to be paid by such corporation. No member of any such board shall, during his continuance in office, be engaged in any other business.

SEC. 203. OFFICERS AND EMPLOYEES OF CORPORATIONS.

(a) The board of directors of a corporation may without regard to the provisions of title 5, United States Code, governing appointments in the competitive service—

(1) appoint a manager of the corporation who shall be compensated at the provided for level II of the Executive Schedule, and

(2) appoint such other officers, employees, attorneys, and agents as are necessary for the transaction of its business, fix their compensation (without regard to the provisions of chapter 51 and subchapter III of

chapter 53 of title 5, United States Code, relating to classification and general schedule pay rates), define their duties, and require bonds of such of them as such board may designate.

Any appointee of a board of directors may be removed in the discretion of such board.

(b) (1) For purposes of the Act of March 3, 1931 (Davis-Bacon Act; 40 U.S.C. 276a), each contract to which the corporation is a party shall be considered a contract to which the United States is a party.

(2) If work, which if let by contract would be subject to paragraph (1), is done directly by a corporation, the prevailing rate of wages shall be paid in the same manner as though such work had been let by contract.

(c) In the appointment of officials and the selection of employees for a corporation, and in the promotion of any such employees or officials, no political test or qualification shall be permitted or given conisderation, but all such appointments and promotions shall be given and made on the basis of merit and efficiency. Any member of a board of directors who is found by the President of the United States to be guilty of a violation of this subsection shall be removed from office by the President of the United States, and any appointee of a board of directors who is found by the board to be guilty of a violation of this subsection shall be removed from office by such board.

SEC. 204. CORPORATE POWERS GENERALLY.

(a) Except as otherwise specifically provided in this Act, a corporation shall have the same powers as a District of Columbia nonprofit corporation as under subsections (a), (b), (c), (d), and (e) of section 5 of the District of Columbia Nonprofit Corporation Act, and in addition—

(1) May make contracts to carry out its functions under this Act.

(2) May adopt, amend, and repeal bylaws.

(3) Shall have power to acquire real property for the construction of generating facilities, transmission lines, and other structures and projects.

(4) Shall have power in the name of the United States of America to exercise the right of eminent domain, in accordance with section 207.

(5) Shall have such powers as may be necessary or appropriate for the exercise of the powers specifically conferred in this Act upon such corporation.

(b) In order to enable a corporation to exercise the powers and duties vested in it by this Act—

(1) The exclusive use, possession, and control of all property to be acquired by such corporation in its own name or in the name of the United States of

America, are entrusted to such corporation for the purposes of this Act.

(2) The President of the United States is authorized to provide for the transfer to such corporation of the use, possession, and control of such other real or personal property of the United States as he may from time to time deem necessary and proper for the purposes of such corporation as stated in this Act.

(c) Each corporation shall maintain its principal office at a place determined by it.

(d) Section 101 of the Government Corporation Control Act is amended by inserting "any corporation established under the National Power Grid Act;" after "Tennessee Valley Authority;".

(e) A corporation may contract with any person or public agency which is deems qualified, to design, prepare specifications and bidding documents, recommend the award of contracts or supervise the construction and installation of equipment and facilities of any required type anywhere in the United States. A corporation may contract with the Federal Power Commission to participate with the staff of such corporation in system planning and load forecasting.

SEC. 205. ACCOUNTS AND CONTRACTS.

(a) A corporation shall at all times maintain complete and accurate books of accounts. Each corporation shall determine its own system of administrative accounts and the forms and contents of its contracts and other business documents except as otherwise provided by law.

(b) Subject to the other provisions of this Act, a corporation is authorized to make such expenditures and to enter into such contracts, agreements, and arrangements, upon such terms and conditions and in such manner as it may deem necessary, including the final settlement of all claims and litigation by or against such corporation; and, notwithstanding the provisions of any other law governing the expenditure of public funds, the General Accounting Office, in the settlement of the accounts of the accountable officer or employee of such corporation, shall not disallow credit for, nor withhold funds because of, any expenditure which the board of directors thereof shall determine to have been necessary to carry out the provisions of this Act.

(c) All purchases and contracts for supplies or services, except for personal services, made by a corporation, shall be made after advertising, in such manner and at such times sufficiently in advance of opening bids, as the board of directors thereof shall determine to be adequate to insure notice and opportunity for competition; except that advertisement shall not be required when, (1) an emergency requires immediate delivery of the supplies or performance of the services; or (2) repair parts, accessories, supplemental equipment, or services are required for supplies or services previously furnished or contracted for; or (3) the aggregate amount involved in any purchase of supplies or procurement of services does not exceed $2,500; in which cases such purchases of supplies or procurement of services may be made in the open market in the manner common among businessmen. In comparing bids and in making awards a board of directors may consider such factors as relative quality and adaptability of supplies or services, the bidder's financial responsibility, skill, experience, record of integrity in dealing, ability to furnish repairs and maintenance services, the time of delivery or performance offered, and whether the bidder has complied with the specifications.

SEC. 206. BONDS FOR FINANCING POWER PROGRAMS.

(a) (1) Each corporation is authorized to issue and sell bonds, notes, and other evidences of indebtedness (hereinafter collectively referred to as "bonds") to assist in financing its activities and to refund such bonds.

(2) the aggregate outstanding amount of bonds issued by the National Grid and by all regional corporations shall not exceed $30,000,000,000 at any time. This paragraph shall not apply to bonds issued by a regional corporation and not guaranteed by the United States.

(b) Subject to section 103(e), payment of principal and interest on bonds issued by a corporation under this section shall be guaranteed by the United States. Proceeds realized by a corporation from issuance of such bonds and from power operations and the expenditure of such proceeds shall not be subject to apportionment under the provisions of section 3679 of the Revised Statutes (31 U.S.C. 665).

(c) (1) Subject to paragraph (2), bonds issued by a corporation under this section shall be negotiable instruments unless otherwise specified therein, shall be in such forms and denominations, shall be sold at such times and in such amounts, shall mature at such time or times not more than fifty years from their respective dates, shall be sold at such prices, shall bear such rates of interest, may be redeemable before maturity at the option of such corporation in such manner and at such times and redemption premiums, and shall be subject to such other terms and conditions as such corporation may determine.

(2) At least 15 days before selling each issue of bonds under this section (exclusive of any commitment shorter than 1 year) a corporation shall advise the Secretary of the Treasury as to the amount, proposed date of sale, maturities, terms and conditions, and expected rates of interest of the proposed issue in the fullest detail possible and, if the Secretary shall so request, shall consult with him or his designee thereon, but the sale and issuance of such bonds shall not be subject to approval by the Secretary of the

Treasury except as to the time of issuance and the maximum rates of interest to be borne by the bonds. If the Secretary of the Treasury does not approve a proposed issue of bonds hereunder within 7 working days following the date on which he is advised of the proposed sale, such corporation may issue to the Secretary interim obligations in the amount of the proposed issue, which the Secretary is directed to purchase. In case such corporation determines that a proposed issue of bonds under this section cannot be sold on reasonable terms, it may issue to the Secretary interim obligations which the Secretary is authorized to purchase. Notwithstanding the foregoing provisions of this subsection, obligations issued by a corporation to the Secretary shall not exceed $750,000,000 outstanding at any one time, shall mature on or before 1 year from date of issue, and shall bear interest equal to the average rate (rounded to the nearest one-eighth of a percent) on outstanding marketable obligations of the United States with maturities from dates of issue of 1 year or less as of the close of the month preceding the issuance of the obligations of such corporation. If agreement is not reached within 8 months concerning the issuance of any bonds which the Secretary has failed to approve, such corporation may nevertheless proceed to sell such bonds on any date thereafter without approval by the Secretary in amount sufficient to retire the interim obligations issued to the Treasury and such interim obligations shall be retired from the proceeds of such bonds. For the purpose of any purchase of a corporation's obligations the Secretary of the Treasury is authorized to use as a public debt transaction the proceeds from the sale of any securities issued under the Second Liberty Bond Act, as amended, and the purposes for which securities may be issued under the Second Liberty Bond Act, as amended, are extended to include any purchases of such corporation's obligations hereunder. A corporation may sell its bonds by negotiation or on the basis of competitive bids, subject to the right, if reserved. to reject all bids; may designate trustees, registrars, and paying agents in connection with such bonds and the issuance thereof; may arrange for audits of its accounts and for reports concerning its financial condition and operations by certified public accounting firms (which audits and reports shall be in addition to those required by sections 105 and 106 of the Government Corporation Control Act) may, subject to any covenants contained in any bond contract, invest the proceeds of any bonds and other funds under its control which derive from or pertain to its power program in any securities approved for investment of national bank funds and deposit said proceeds and other funds, subject to withdrawal by check or otherwise, in any Federal Reserve bank or bank having membership in the Federal Reserve System; and may perform such other act not prohibited by law as it deems necessary or desirable to accomplish the purposes of this section. Bonds issued by a corporation under this section shall contain a recital that they are issued pursuant to this section, and such recital shall be conclusive evidence of the regularity of the issuance and sale of such bonds and of their validity.

(d) Bonds issued by a corporation under this section shall be lawful investments and may be accepted as security for all fiduciary, trust, and public funds, the investment or deposit of which shall be under the authority or control of any officer or agency of the United States. The Secretary of the Treasury or any other officer or agency having authority over or control of any such fiduciary, trust, or public funds, may at any time sell any of the bonds of a corporation acquired by them under this section.

(e) Bonds issued by a corporation under this section shall be exempt both as to principal and interest from all taxation now or hereafter imposed by any State or local taxing authority except estate, inheritance, and gift taxes. Interest on such bonds shall not be included in gross income for purposes of any tax imposed by subtitle A of the Internal Revenue Code of 1954.

(f) The section shall apply to bonds of the Tennessee Valley Authority, only if such bonds are guaranteed by the United States, in accordance with section 103 (e).

SEC. 207. CONDEMNATION PROCEEDINGS.

A corporation may cause proceedings to be instituted for the acquisition by condemnation of any lands, easements, or rights-of-way, or of any transmission capacity or existing facilities referred to in section 103 (C) (2) (A) or (B), which, in the opinion of such corporations, are necessary to carry out the provisions of this Act. The proceedings shall be instituted in the United States district court for the district in which the land, easement, right-of-way, or other interest, or any part thereof, is located, and such court shall have full jurisdiction to divest the complete title to the property sought to be acquired out of all persons or claimants and vest the same in the United States in fee simple, and to enter a decree quieting the title thereto in the United States of America. In any such eminent domain proceeding (including a proceeding in the District of Columbia) a corporation may file with the complaint or at any time before judgment a declaration of taking in the manner and with the consequences provided by the first section and sections 2 and 4 of the Act entitled "An Act to expedite the construction of public buildings and works outside the District of Columbia by enabling possession and title of sites to be taken in advance of final judgment in proceedings for the acquisition thereof under the power of eminent domain", approved February 26, 1931 (46 Stat. 1421).

SEC. 208. REPORTS.

(a) Each corporation shall report to the President annually, and the President shall transmit the report to the Congress with such comment and recommendations as he deems appropriate.

(b) Each corporation shall file with the President and with the Congress, in December of each year, a financial statement and a complete report as to the business of such corporation covering the preceding fiscal year.

(c) Reports provided for in subsections (a) and (b) shall also be noticed in the Federal Register.

SEC. 209. ADVISORY COMMITTEES.

(a) Whenever any corporation shall establish or utilize any board, task force, commission, committee, or similar group, not composed entirely of members of the board and officers or full-time employees of the corporation, for the purpose of advising the corporation as to its policies and procedures, the corporation shall insure that each such group is fairly balanced in terms of the points of view represented by its members.

(b) Each meeting of such board, task force, commission, committee, or similar group, shall be open to the pub-

UNIVERSITY OF FLORIDA
3 1262 09113 8551

lic, and interested persons shall be permitted to attend, appear before, and file statements with, such group.

(c) All records, reports, transcripts, memoranda, and other documents which were prepared for or by such group, shall be available for public inspection and copying at a single location in the offices of the corporation.

(d) Advisory committees established or utilized pursuant to this Act shall be governed in full by the provisions of the Federal Advisory Committee Act (Public Law 92–463, 86 Stat. 770), except as inconsistent with this section.

(e) This section shall apply to the Tennessee Valley Authority.